

REPORT TO THE CONGRESS



BY THE COMPTROLLER GENERAL
OF THE UNITED STATES

U.S. Coal Development-- Promises, Uncertainties

Coal represents 90 percent of the Nation's total fossil fuel reserves. Yet, it currently supplies only 18 percent of energy needs.

The administration proposes to double annual coal production and use to 1.2 billion tons by 1985, up from 665 million tons in 1976.

GAO believes that achieving 1.2 billion tons is highly unlikely--in fact, it will be very difficult to achieve 1 billion tons annually by 1985.

In this report, GAO summarizes available knowledge on U.S. coal development and seeks to identify under these chapter headings policy issues that must be considered.

- How much do we need?
- How much do we have?
- How do we get it?
- How can we get it to where we need it?
- How can we make it usable?
- How can we solve the social problems?
- What is the U.S. position in the world coal market?
- Where do we go from here?

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COMPTROLLER GENERAL OF THE UNITED STATES

WASHINGTON, D.C. 20548

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To the President of the Senate and the
Speaker of the House of Representatives

This report presents our analysis of the prospects for developing America's vast coal resources. The report summarizes available knowledge on U.S. coal development, and seeks to identify the major policy issues that must be considered--especially if we are to achieve the coal production and use goals in the Administration's National Energy Plan.

We made our review pursuant to the Budget and Accounting Act of 1921 (31 U.S.C. 53), and the Accounting and Auditing Act of 1950 (31 U.S.C. 67).

To assist our analysis, we selected two energy scenarios--the Bureau of Mines (high-growth) energy forecast through the year 2000, and the Edison Electric Institute low-growth scenario. We believe that these scenarios represent possible ranges of high and low energy demands, and that actual future energy demand likely will fall somewhere between the two. The coal projections in the National Energy Plan were not available until near the end of our review, but we have considered them wherever possible.

Why is America's Coal Important?

Coal represents 90 percent of our total fossil fuel reserves, yet it currently supplies only 18 percent of our energy needs.

Our coal resources become even more important when we consider that

- our domestic oil and gas supplies are limited, and declining rapidly;
- nonconventional energy sources, such as solar and geothermal, are unlikely to contribute significantly to our energy supplies for the next 25 years or so; and

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--the Administration proposes to reduce our ever increasing dependence on insecure foreign energy sources.

Why Aren't We Using More Coal?

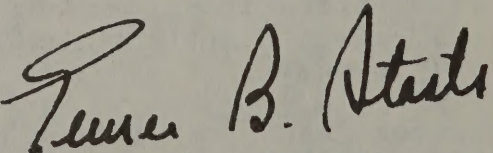
While the actual tonnage of coal produced and used has increased through the years, coal use has declined relative to other fuels. Coal is less convenient than alternative fuels and causes more harm to the environment.

Recent coal prices have not been as attractive as those of other energy resources for a number of reasons, including:

- Uncertain environmental standards (both land and air).
- Possible increased capital and operating costs due to environmental control requirements.
- Transportation and storage problems.
- The relative cost advantages of nuclear power.

In the following chapters, we discuss the status, prospects, and major issues in U.S. coal development from the standpoints of demand, supply, production, transportation, environmental and socioeconomic impacts, and America's position in the world coal market.

Copies of this report are being sent to the Secretary Designate, Department of Energy; the Director, Office of Management and Budget; the Secretaries of the Interior and Transportation; the Administrators of the Federal Energy Administration, the Energy Research and Development Administration, and the Environmental Protection Agency; the Chairman, Federal Power Commission; and to the chairmen of energy related congressional committees.


Comptroller General
of the United States

D I G E S T

Why is America's coal important?

It represents 90 percent of the Nation's total fossil fuel reserves. Yet, it currently supplies only 18 percent of energy needs. Coal's importance grows, however, when you consider that

- domestic oil and gas supplies are limited, and declining rapidly;
- nonconventional energy sources, such as solar and geothermal, are unlikely to contribute significantly to energy supplies for the next 25 years or so; and
- dependence on insecure foreign energy sources continues to increase.

In its National Energy Plan, the administration expects annual coal production and use of 1.2 billion tons by 1985, up from 665 million tons in 1976.

Can this Nation double its annual coal production and use by 1985? GAO believes not.

GAO's recent report An Evaluation of the National Energy Plan pointed out that achieving 1.2 billion tons is highly unlikely--in fact, it will be very difficult to achieve one billion tons annually by 1985. (See pp. 2.40 and 2.41.)

This report offers the detailed analyses that support GAO's conclusions. GAO discusses the status, prospects, and major issues in U.S. coal development from the standpoints of demand, supply, production, transportation, environmental and socioeconomic impacts, and America's position in the World coal market.

For analytical purposes, GAO selected two energy growth scenarios representing possible high and low energy demand ranges--the Bureau of Mines (high growth) energy forecast through the year 2000, and the Edison Electric Institute low-growth scenario. Actual energy demand likely will fall somewhere between the two.

Wherever possible, GAO also used the coal projections in the National Energy Plan, although they were not available until near the end of the review.

HOW MUCH DO WE NEED (OR CAN WE USE)?

There is no hard, fast figure on how many tons of coal the Nation needs by 1985.

The coal demand estimates that are available vary tremendously. The Edison Electric Institute scenario calls for 779 million tons annually by 1985, the Bureau of Mines says 988 million tons, and the National Energy Plan calls for 1.2 billion tons. (See pp. 2.41 and 4.1.)

Given the objectives of reducing energy imports and protecting our dwindling oil and gas supplies, the Nation needs all the coal it can possibly mine and burn--without doing irreparable damage to the environment.

Why aren't we using more coal? The actual tonnage of coal produced and used has increased through the years, but has declined relative to other fuels. Coal is less convenient than other fuels and causes more harm to the environment. Coal has not been as attractive as other fuels for a number of reasons, including

- uncertain environmental standards (both land and air),
- possible increased capital and operating costs due to environmental control requirements,
- transportation and storage problems, and
- the apparent relative cost advantages of nuclear power. (See pp. 2.1 to 2.5.)

GAO believes that a substantial increase in coal use will occur. However, there are a number of obstacles that will hinder doubling coal production and use by 1985. The opportunities for greater coal use are discussed in relation to:

- Short- and long-term opportunities for coal use in the electrical sector. (See p. 2.8.)
- Coal use in other sectors through direct burning and synthetic fuel development. (See p. 2.23.)

In the near term--the next decade or so--coal will be used principally for electric power, and to a lesser extent to provide steam for industrial purposes. In the long term, depending on technological development and the cost of alternative fuels, coal may be converted into gases and liquids and substituted for natural gas and petroleum. (See pp. 2.3 and 2.4.)

The electrical sector has the best potential for coal substitution. The 1973 oil embargo and subsequent price increases stimulated Government action to force electric utilities and others to switch from natural gas and oil to coal. (See p. 2.8.)

Under the Energy Supply and Environmental Coordination Act, this conversion effort has not lived up to expectations. This is principally due to the difficulty and cost in switching to coal and burning it in compliance with clean air standards. GAO believes the provisions of the act could be strengthened to expedite the fuel conversion process. (See p. 2.8 to 2.12.)

More coal could be substituted for oil and gas by increasing electricity use and efficiency. One possibility is reducing peak load electricity demand by making it more expensive than off-peak electricity. Another is improving coordination among power pools or other electric power exchange mechanisms. Another short-term possibility is making electricity generation and use equipment more efficient so that less energy is wasted.

Were all three of these actions to occur, electricity could become much more attractive and electric utility coal consumption could rise substantially. This, in turn, would mean an offset to U.S. oil imports. (See pp. 2.12 and 2.13.)

Over the next 25 years, coal and nuclear power increasingly will displace oil and gas for baseload electric capacity. Hydroelectric and geothermal energy development opportunities are limited and these sources are not likely to become significant. (See p. 2.17.)

Until recently, utility expansion plans indicated that nuclear energy was the apparent choice for baseload electric power generation, because it was considered least costly. (See p. 2.18.)

The potential for nuclear power is less certain now than it once was, however, because there is a growing awareness that previous estimates of nuclear power have been too optimistic. In addition, recent moves by the administration to stop nuclear fuel reprocessing and defer the fast breeder reactor further becloud the long-term outlook for nuclear power. As utilities have reduced their expansion plans, they have cancelled more proposed nuclear powerplants than coal plants. (See pp. 2.18 to 2.23.)

In the residential/commercial sector, there is not much opportunity for direct coal use, but a large portion of the increased energy use to 1985 may be from electricity generated with coal in lieu of gas and oil. (See p. 2.24.)

The industrial sector has some potential for direct substitution of coal--as boiler fuel--but will mainly rely on electricity. (See pp. 2.25 and 2.26.)

The transportation sector appears to be the least amenable to increased reliance on coal. This sector relies on oil almost exclusively. The prospects for coal substitution here depend on the

- outlook for electric rail transport,
- growth of electrified intra-city mass transit systems,
- outlook for the electric car, and
- development of coal-based synthetic liquid fuels. (See p. 2.26.)

Energy demand and coal's portion are difficult to project because of three variables--population and economic growth; composition of national output; and the cost of energy relative to that of other resource inputs. (See p. 2.33.)

In its earlier report to the Congress, An Evaluation of the National Energy Plan, GAO assessed the various administration recommendations to increase coal use and concluded that a lot more needs to be done. (See p. 2.40.)

The work GAO was then doing for this report raised doubts about achieving the administration's goal of producing and using 1.2 billion tons of coal annually by

1985. Given all the physical, economic, environmental, and public health considerations, it appeared to GAO that producing and using even one billion tons per year by 1985 would be very difficult. (See p. 2.40.)

GAO calculated that using the average Btu conversion rate factors used by the administration, a 200 million ton shortfall in 1985 would cause the need for an additional 2.3 million barrels of imported oil per day. (See p. 2.40.)

Subsequently, using more appropriate conversion factors which reflect each end use where coal would substitute for oil, GAO estimated the oil shortfall noted above at 2.2 million barrels of oil equivalent per day. (See p. 2.40.)

Using this same conversion factor analysis, GAO also estimates that the oil equivalency of the remaining one billion tons of coal could be 1.1 million barrels of oil equivalent per day less than the administration's figures, as shown in the fuel balance tables in the National Energy Plan. (See pp. 2.41 to 2.43.)

If this further difference implies a real world shortfall, it would have to be made up in one of three ways: additional imports; increased domestic production from other sources; or increased conservation efforts. (See p. 2.43.)

If, on the other hand, the oil equivalent numbers in the National Energy Plan simply reflect a mechanical use of an average conversion factor from detailed estimates based on actual quantities, there would be no shortfall. However, both supply and demand would be less in barrels of oil equivalent using the GAO conversion factors. (See p. 2.43.)

GAO believes its work raises questions about the oil equivalent figures for other domestic energy sources, which in turn raises questions about the administration's total estimates regarding energy supply and demand. While not part of this study, GAO is continuing its analysis and will be reporting its findings to the Congress. (See p. 2.43.)

HOW MUCH DO WE HAVE?

There are no hard, fast figures that policymakers can rely on. Current data on coal resources and reserves are extremely spotty and outdated.

The current "best estimate" says we have 3.9 trillion tons of coal--1.7 trillion are called identified resources, and 2.2 trillion tons are called hypothetical (undiscovered) resources. (See p. 3.1.)

Why are accurate data so important?

First, because coal is a finite resource and will not last forever. Of the identified resources, 256 billion tons presently are considered to be economically recoverable. That amount would last only about 74 years under the Bureau of Mines high-growth scenario. (See p. 3.1.)

Secondly, certain coal with highly desirable qualities is much more limited in supply. For example, accurate reserve data on metallurgical coal, essential in manufacturing steel, could affect policy decisions on exporting it. (See pp. 3.16 and 8.1.)

Furthermore, coal varies greatly in terms of heat value, pollutants, accessibility, and combustion characteristics. For example, low-sulfur coal is desirable because of air quality standards. However, most low-sulfur coal is located in the Western States--considerable distance from traditional coal consuming centers. (See pp. 3.5, 3.11, and 3.12.)

Accurate reserve data on low-sulfur coal could affect both air pollution regulations, and leasing decisions for the vast Federal coal resources in the West. (See pp. 3.10 to 3.14.)

GAO believes that more accurate coal resource and reserve data are needed to permit sound public policy decisions on what kind of coal to mine, where, and when.

Such data could be obtained in several ways, including:

- Federal stratigraphic drilling and mapping.
- Tax and other incentives to coal companies for submitting accurate, uniform reserve data to the Government. (See p. 3.22.)

HOW DO WE GET IT?

We will mine it, of course, but it is not quite that simple.

To achieve the coal production levels in the two scenarios, we will have to

- open 438 to 825 new mines,
- recruit and train 288,300 to 531,600 new miners,
- manufacture enormous quantities of mining equipment,
- come up with \$26.7 to \$45.5 billion in capital, and
- continue to improve mining health and safety conditions and increase productivity. (See p. 4.1.)

The coal industry may be hardpressed to meet these requirements. However, GAO found that 11 major coal producers believe the industry can double coal production by 1985 and triple it by 2000 under existing conditions. (See p. 4.16.)

This may be true, but GAO believes many things must fall into place.

For example, mining equipment manufacturers will have to fill orders promptly, and coal producers must have the foresight and capital to open mines when the added production is needed. In addition:

- Coal mining productivity (tons produced per worker day) must improve. It has been declining since 1969. (See pp. 4.5, 4.6, 4.24, and 4.25.)
- Good labor-management relations must be established. (See pp. 4.27 to 4.31.)
- New workers must be found and trained. This includes mining engineers. (See pp. 4.21 to 4.24.)
- Mining technology must be improved. (See pp. 4.25 and 4.26.)

The declining productivity, especially in underground mines, has resulted from many factors including:

- The 1969 Federal Coal Mine Health and Safety Act, which resulted in more personnel in the mines.
- The introduction of numerous inexperienced miners.
- Additional personnel required per union agreements.
- Unscheduled interruptions due to wildcat strikes and absenteeism.
- Changes in mining conditions such as quality of mine roofs, types and widths of coal seams, and distances from mine entrances to the operating faces. (See p. 4.6.)

Labor-management relations might be the most important consideration. In years when a national agreement is renegotiated, the lost time due to work stoppages is considerable. In 1974, for example, eight percent of the total worktime was lost. (See pp. 4.28 and 4.29.)

The current national agreement will expire on December 6, 1977. This involves the United Mine Workers and the Bituminous Coal Operators Association, Western Surface Miners, and National Construction Contractors. A major point of contention between union and industry at present is the right to strike over local grievances. (See p. 4.30.)

Another major constraint GAO sees is the leadtime required to open new mines. This can range anywhere from 1 to 15 years depending on the location and type of mine. (See pp. 4.10 to 4.12.)

HOW CAN WE GET IT TO WHERE WE WANT IT?

Railroads carried 65 percent of this Nation's coal during 1975, and they will continue to be the principal coal transporters in the foreseeable future. (See p. 5.3.)

Other transportation modes also will expand as part of the total transportation system. However, these other modes are ultimately limited by physical, economic, and/or environmental constraints. (See pp. 5.1, 5.2, and 5.7.)

The Nation's inland waterway system, for example, carries over 100 million tons of coal each year, and is the cheapest transportation mode. However, the system does not directly serve many areas scheduled for major coal development and is hindered by ice in the winter and the physical capacity of its locks. (See pp. 5.28 to 5.30.)

Trucks cannot compete with railroads because of costs. A 1974 report to the Interagency Coal Task Force showed truck costs per ton-mile to be five times higher than railroads (\$.05/ton-mile vs. \$.01/ton-mile). (See p. 5.5.)

Another alternative is to build powerplants near the mines and transport the electricity over extra-high voltage transmission lines. A recent Bureau of Mines study, however, found this to be about 30 percent more expensive than shipping the coal on railroads. (See p. 5.25.)

Coal slurry pipelines appear to be economically competitive with railroads, but they are constrained by many other problems. For example, pipelines require enormous amounts of water at the point of shipment--a key constraint in arid western coal fields. There is also a problem of disposing of the pipeline effluent at the destination. (See pp. 5.22, 5.26, and 5.27.)

Coal slurry pipelines also face a big legal hurdle in trying to assemble rights-of-way, often over property owned by the railroads. (See pp. 5.25 and 5.26.)

Obviously it will fall to the railroads to move the bulk of any greatly expanded coal production. The railroads are confident they can handle the amounts forecast in the energy growth scenarios and in the National Energy Plan. They expect to move 95 percent more coal in 1980 than they did in 1974. (See pp. 5.7 and 5.8.)

There will be problems, however, particularly in finding enough capital to purchase equipment and upgrade existing lines. (See pp. 5.15 to 5.17.)

A recent survey of the railroads showed the following planned investments to meet 1980 coal needs:

<u>Item</u>	<u>Total Investment</u> (millions)
Hopper cars	\$2,900
Locomotives	665
Physical plant	1,559
Maintenance facilities	103
	<u>\$5,227</u>

Over half of this investment will occur in the western rail district. (See p. 5.10.)

That \$5.2 billion does not include the \$4.9 billion, 10-year rehabilitation program for Conrail, the Federally subsidized consolidation of insolvent eastern and mid-western railroads. (See pp. 5.11 and 5.19.)

GAO concludes that the Nation's transportation system can be expanded to meet expected needs. In part, this conclusion reflects the transportation industry's confidence that transport facilities can be put into place as fast or faster than new mines can be opened and new boiler capacity installed. (See p. 5.31.)

HOW CAN WE MAKE IT USABLE?

The environmental issue is paramount.

We cannot use one billion tons of coal in one year without harming our environment. At least not with current technology.

This is a tradeoff. We are relinquishing some of our environmental quality to reduce our energy imports and extend the life of our dwindling oil and gas reserves. The tradeoff is made in each step of the coal fuel cycle--mining, transporting, and using. (See p. 6.1.)

The environmental problems fall into three general categories

- problems we have been aware of for a long time and have taken steps to control,
- problems we have more recently become aware of and are taking steps to control, and
- new problems on the horizon which we are just beginning to study.

The first category primarily deals with air pollution caused when coal is burned. Beginning in 1963, the Congress enacted a number of laws to control air pollution. (See p. 6.2.)

The law most affecting current coal combustion is the Clean Air Amendments of 1970, as amended. This law directed the Environmental Protection Agency to establish minimum national air quality standards. This resulted in primary and secondary standards being established for various classes of pollutants. (See pp. 6.2 and 6.3.)

These standards will necessitate scrubbers and desulfurization techniques in many coal-burning plants. These techniques can help maintain our air quality, but they are costly. (See pp. 6.3 to 6.5.)

GAO estimates the cumulative additional capital costs for controlling emissions to be \$19.1 billion and \$26.4 billion in 1985 and 2000, respectively. Annual operating costs would be \$1.3 billion and \$2.3 billion in each respective year. These costs will not be evenly distributed across the Nation, but will vary widely by geographic region. (See pp. 6.5 to 6.8.)

The second category of environmental problems primarily involves adverse impacts from underground and surface mining operations.

The major reclamation problem in surface mining is dealing with surface disruption. (See p. 6.23.)

The Bureau of Mines scenario estimates that between now and 1985, surface mining annually will disrupt over 150 square miles of land. This means that each year we will be digging up an area over twice the size of the District of Columbia. (See pp. 6.34 and 6.35.)

The recent Surface Mining Control and Reclamation Act prohibits such mining in certain areas, and requires that surface-mined land be restored as nearly as practicable to its original contour. (See pp. 3.17 to 3.19.)

Underground mining poses somewhat different reclamation problems. These include

- controlling or preventing the land from sinking,
- controlling or abating acid drainage that can pollute underground water,

--disposing of waste materials mined with the coal,
and

--controlling or extinguishing coal fires. (See p.
6.23.)

These reclamation efforts are neither easy nor inexpensive. Under the Bureau of Mines scenario, total surface and underground mining reclamation costs would be about \$1.2 billion in 1985 and \$1.9 billion in the year 2000. This is almost as much as the annual cost of operating emission control scrubbers. (See p. 6.32.)

The third category of environmental problems involves those that have not yet been fully studied and for which we cannot presently estimate all the potential consequences. These include:

--Enormous quantities of sludge that accumulate in air pollution control devices and which must be disposed of. (See pp. 6.20 and 6.21.)

--Currently uncontrolled emissions from coal burning plants, including trace elements, particulates, carbon dioxide, and waste heat. (See pp. 6.15 to 6.20.)

Scrubbers may be a key element in cleaning up air pollution from coal. But, they will give rise to a whole new pollution problem--sludge. Under the Bureau of Mines scenario, by 1985 the amount of sludge generated each year could be about the same as the total municipal solid waste produced in America in one year. (See pp. 6.20, 6.21, and 6.50.)

Coal combustion also releases about 53 elements referred to as "trace elements." These include mercury, lead, beryllium, arsenic, and fluorine. Coal combustion also releases minute "particulates" of soot and fly ash.

Both the trace elements and particulates are considered dangerous, but very little research has been done on them. (See pp. 6.15 to 6.18.)

Another uncontrolled substance is carbon dioxide. Its build-up in the atmosphere, according to some experts, causes a "greenhouse effect." This could eventually cause global warming trends, and result in redistribution of temperature patterns and rainfall levels. (See p. 6.19.)

In the years ahead as we begin to use more coal, much more will be heard about these developing environmental problems.

HOW DO WE SOLVE THE SOCIAL PROBLEMS?

Increased coal production will expand both the industry and communities surrounding the development areas.

The newcomers will need public facilities and services immediately, but the revenues to pay for them will not be available--not until the powerplants, mines, and new citizens begin paying taxes. (See pp. 7.1, 7.4, 7.30, and 7.40.)

To meet this time lag, communities will need advance or front-end financing. On a nationwide basis, these costs might run as high as \$4.4 billion by 1985, and another \$10.5 billion between 1985 and 2000. (See pp. 7.9 and 7.10.)

The biggest impact will be on sparsely-populated areas, such as those in the West. The people brought to these communities by the coal development projects may well outnumber the original residents. They will bring their own social, political and moral values, and will change the character of the communities. (See pp. 7.30 to 7.32.)

Through adequate planning and financing, the blow can be cushioned, to be sure, but it will be a blow nonetheless, and the social fabric of the community will be rent and another formed from it. (See p. 9.10.)

WHAT IS THE UNITED STATE'S POSITION IN THE WORLD COAL MARKET?

America's coal resources make up more than 25 percent of the world total, and we are the world's largest producer and exporter. (See p. 8.1.)

Our 1975 coal exports contributed \$3.3 billion toward a favorable balance of payments. Of the 65.7 million tons exported that year, about 50.6 million tons (77 percent) were used metallurgically by foreign steel manufacturers. Over 86 percent of that was purchased by Japan, Canada, and the European Economic Community. (See pp. 8.1 and 8.15.)

U.S. metallurgical coal is among the highest quality in the world, and both domestic and foreign steel producers want it for their steel making processes. (See p. 8.1.)

Despite stronger competition from other exporting countries, U.S. exports of metallurgical coal are expected to increase from about 51 million tons in 1975 to between 55 and 61 million tons in 1985, and between 70 and 77 million tons in 2000. (See pp. 8.13 and 8.14.)

Supplies of metallurgical coal are limited, however, and data on its production, use, and export have not been routinely collected by the Bureau of Mines. This has led to some uncertainty about the quality of metallurgical coal exported, and whether these exports will hinder U.S. steel production. (See pp. 8.1, 8.13, and 8.15.)

U.S. steam coal, used by foreign utilities to generate electricity, is not competitive and, except for Canada, its exports are expected to increase only slightly. (See p. 8.13 and 8.14.)

WHERE DO WE GO FROM HERE?

If coal is to help reduce our dependence on oil imports and relieve pressure on our dwindling domestic natural gas reserves, then certain Federal Government actions will be necessary. The administration has already proposed in the National Energy Plan a number of Federal actions to increase coal use. These include

- a regulatory program requiring coal use by utilities and large industries, with allowances for exceptions;
- an oil- and gas-users tax and rebate/investment tax credit system providing an economic stimulus to convert to coal;
- an environmental policy for coal to achieve the energy goals without endangering public health or degrading the environment; and
- a research program for coal conversion, mining, and pollution control technology. (See pp. 9.13 and 9.14.)

In its report, An Evaluation of the National Energy Plan, GAO pointed out that the administration's plan deals with some of the constraints to increased coal use, but does not deal with transportation, productivity, and other constraints to achieving 1.2 or even one billion tons of coal production and use in 1985. GAO noted the need for

- capital to upgrade large portions of the Nation's railroads, particularly in the Eastern States, together with the need to expand existing capabilities;
- congressional resolution of the rights-of-way issue for coal slurry pipelines;
- improved labor relations to prevent disruptions due to wildcat strikes, together with the need for improved miner health and safety conditions, recruitment, and training;
- greater productivity;
- accelerated Federal research to determine the health and environmental effects of burning greater amounts of coal; and
- less costly and more reliable technology to control air pollution from coal burning facilities. (See p. 9.14.)

The coal industry's very short run capacity (a year or so) is limited to what can be extracted through increased production at existing mines (surge capacity). (See p. 9.15 to 9.17.)

So many interrelated elements would have to work to double coal production by 1985, that GAO does not believe it could happen: to name only two, mining equipment manufacturers would have to fill orders promptly and mining companies must have the foresight and capital to be able to open new mines when the added output is needed. (See p. 9.14.)

During the period to 1985, coal is not only supply constrained, but is also demand constrained in the sense that utility and industrial users are not going to buy coal if they cannot use it. There are long lead times involved just in building and installing boilers at existing plants, not to mention the lead times involved in planning and building completely new coal burning plants. (See pp. 9.14 and 9.15.)

In the medium term (1985-2000), coal is demand-constrained. The possibilities of direct substitution for oil or gas are very limited on an economy-wide basis. The prospect for indirect substitution by coal-generated electricity, while more promising, is limited too by economics and the current state of industrial and transportation technology.

Over a longer term (beyond 2000), coal seems to be both supply-constrained, especially in terms of low-sulfur and metallurgical coal, and demand-constrained. GAO believes that the very long-term prospects for increased coal demand ride upon the hope of coal gases and liquids becoming environmentally-safe and economical. (See p. 9.15.)

These, then, are the physical and economic limits of the coal solution.

If maximum coal output and consumption can be achieved within these limitations, the tradeoffs will be costly, particularly in terms of human life and disease. These tradeoffs can only be considered tolerable when viewed in the broader context of the Nation's inadequate oil and gas resources as well as the risks and limits of nuclear power. (See p. 9.15.)

Indeed, the coal tradeoffs are important enough to reemphasize the need for vigorous energy conservation--not as an alternative to coal, but to temper somewhat coal's very high social and economic costs. (See p. 9.15.)

Because of the long leadtimes to translate Government policy and action into actual coal production and consumption, GAO believes it is realistic to assume that government policies set in motion now will have some effect by 1985, but the greater impact will be in the 1985-2000 period. (See p. 9.15.)

With all the constraints, however, increased coal use in absolute terms will still be substantial. Electric utility plans through 1985 call for an increase of over 300 million tons. Given all the constraints, this is probably on the high side, but it is unclear how much. Industrial use will increase also, but more slowly. (See p. 9.17.)

There is no question that coal will supply a large part of the Nation's energy future. So will foreign oil and nuclear power. Natural gas will decline and probably have to be restricted to optimum end uses such as home heating, etc.; domestic oil will decline. Solar energy will increase slowly, as a complement to other fuel types. (See p. 9.17.)

On the demand side, the best answer to the Nation's energy bind is conservation, through increased efficiency and decreased use. (See p. 9.17.)

Agency Comments

A draft of this report was provided to numerous Federal agencies for their review. The agencies generally agreed with the report, and their comments were considered in preparing the final report.

A copy of the final draft was provided to the Energy Policy and Planning staff in the Executive Office of the President. The staff's only major area of substantive disagreement is with GAO's conclusion that it will be very difficult for this Nation to produce and use one billion tons of coal annually by 1985. The staff's comments are included at page VIII.1. GAO's evaluation of those comments begins on page 9.17.

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CHAPTER 1

INTRODUCTION

WHAT IS THE PROBLEM?

In late 1973 and early 1974, the international oil cartel quadrupled the price of crude oil; in addition, the Arab nations within the cartel temporarily withheld oil shipments to the United States. These actions--one economic, the other political--made it very difficult to ignore for any longer the unpleasant facts about U.S. domestic oil supply. U.S. proved oil reserves and production had, indeed, been declining since 1970. The Nation had relied increasingly upon oil imports to fill the gap between dwindling domestic oil supply and growing domestic consumption.

The lesson to be drawn from those international events was simple enough: imported oil is vulnerable--to interruptions in supply and to large price increases. And given this premise, the policy consideration is easily agreed upon: How can the United States become less dependent on oil imports to meet its energy needs?

But from here on, nothing is simple or easy. The United States is even more reliant on oil imports today than it was in 1973--oil imports account for 42 percent of U.S. oil consumption, compared with 35 percent 4 years ago. This is a tribute to both the complexity and short-term intractability of our energy system as well as to the difficulty our political institutions have in grappling with them. Energy policy decisions inevitably cut across many deep-seated special interests--regional, economic, and environmental--and the result is political conflict which is especially difficult to resolve. Decisions about coal are no exception.

IS COAL THE ANSWER?

Coal is part of the answer. That there is renewed interest today in coal as an alternative energy source whose increased development might reduce United States reliance on imported oil is due to coal's principal, perhaps only attribute--there is a lot of it. Coal is dirty; it is bulky; it seldom occurs where you need it; and it varies widely in quality, in terms of chemical impurities, heat content, and combustion characteristics. At every stage of its development, coal has problems--in mining, refining, transporting, storing, and burning. It is not surprising, therefore, that coal demand has been declining relative to other energy sources, especially oil and natural gas, for the past 15 years. In 1950 coal met 34 percent of the United States' total energy demand. By 1975, it had sunk

to 17 percent. Commercial, household, and transportation uses of coal have dropped to almost nothing. In industry, coal declined from 46 percent of the energy consumed in 1950 to 19.5 percent in 1975. Only in the electrical generation sector has coal held its own. In 1950 some 45 percent of the energy consumed by electric utilities came from coal. In 1975 it was just a point lower --44 percent.

From the standpoint of national energy planning, coal poses some special problems, the foremost of which is that coal is not readily substitutable for oil. In transportation, which accounts for 53 percent of U.S. oil consumption, it is not currently substitutable at all; its transportation potential lies with development of electric locomotives, and light, short distance road vehicles, and possibly some synthetic liquid fuels from coal in the future. In space heating and air conditioning, the substitution possibilities are usually indirect--oil is replaced by electricity, some of which is generated in coal-fired plants. In the industrial sector oil boilers can be replaced with coal boilers, but it is expensive and because of the inherent disadvantages of coal--bulk and dirt--industries tend to substitute electricity for oil instead. In the future, synthetic gas and liquids could supplement supplies of the industrial and residential/commercial sectors if the economic, technological, and political problems are resolved. Even the most promising area for direct substitution of coal for oil--the electric utility sector--is fraught with uncertainty. To date, utilities have not reconverted many oil-fired plants to coal. There are several reasons for this reluctance including the high cost of capital in general, the capital cost differential between oil and coal plants, the greater cost of pollution control for the coal plant, and the nuisance factor of handling coal compared to other fuels.

For electric utilities to expand coal use, they need stability of coal supply and use conditions over the life of their generating stations in order to make affirmative coal decisions. Similarly, coal producers and transporters require long-term commitments for the development of mines and transportation systems. Factors of stability include the environmental conditions, cost, and associated technology under which coal is mined, transported and burned. Federal and State air pollution controls have been in a state of flux since 1968. Air pollution legislation has forced utilities into long-term technology investments for which they question the reliability and permanence. Major changes in State severance taxes can also add to the uncertainty of long-term investment decisions made by utilities, mining companies and transporters of coal.

Further, it takes time if the utility decides, in spite of the uncertainties, to substitute coal for oil. It takes 5 to 10 years to plan, build, and make operational a coal-fired powerplant. (For a nuclear powerplant, which also is subject to uncertainties, it takes even longer--10 to 13 years.) In other words, plans started today for new capacity to increase coal's share of the electricity generation market by replacing oil cannot have any impact on oil imports until at least 1982.

There is no question, however, about coal's abundance. U.S. coal reserves contain three times as much potential energy in Btus as Middle East oil reserves. Even under high projections for coal demand, U.S. domestic coal supplies should be adequate for at least another 70 to 80 years and maybe longer at comparatively reasonable prices.

Coal is presently mined in seven coal mine provinces which can be grouped roughly in three broad geographic regions. The Eastern region, the oldest coal producing area in the Nation, encompasses most of the Appalachian States. Bituminous coal found and mined in this region, generally characterized by high heat value, includes valuable metallurgical or coking coal prized by the steel industry here and abroad. In fact, most of the U.S. coal exports, which annually account for about 11 percent of total U.S. coal production, come from this region. The sulfur content of this region's coal varies, but only about 20 percent of available deposits are estimated to meet sulfur content requirements of the Clean Air Act.

Moving west, the Ohio, Illinois, and Indiana area has large deposits of bituminous coal, unfortunately with high sulfur content. Its current market as a fuel for utilities is limited, primarily because of air pollution regulations. Surface (strip) mining is dominant in this region.

Most coal reserves of the United States are found in the Western coal region. These large reserves of the subbituminous and lignite varieties have a relatively low heat value but also a low sulfur content. Thick seams close to the surface make cheaper stripping methods the logical technique of mining. It is here that large-scale new coal development is expected to occur.

WHAT ARE THE TRADEOFFS?

Energy policy decisions relate to certain broad national goals

--reliability of supply,

- efficient resource allocation,
- minimum environmental damage,
- independence of foreign policy,
- equitable distribution of costs, and
- economic growth.

Our starting point is the first energy policy goal--reliability of supply. Specifically, can the United States achieve reliability of energy supply through increased dependence on domestic coal? And equally important--what are the costs--human, environmental, economic, and social--of increasing coal production? Can these costs be mitigated?

We have attempted in this report to identify those costs which cannot be fully mitigated; this is crucial for it is the only way the tradeoffs can be weighed. For example, some farmland which is stripped for coal and then carefully recovered to close to its former condition, may not regain its original productivity per acre. Is this irreversible cost worth the contribution made to reliability of supply?

For another example, there are certain irreversible human costs to achieving this goal. Underground coal mining is the most dangerous occupation in the United States. However vigorously health and safety regulations are pursued, in a mining operation some miners are going to get black lung disease (pneumoconiosis) or meet with accidents, many fatal. This is another tradeoff for greater reliability of supply. Or for another example, increased coal development in Sweetwater County, Wyoming, will inevitably change the fabric of that area's way of life--it will become noisier, more impersonal, and less relaxed, regardless of the socio-economic countermeasures which are implemented. This is a tradeoff for greater reliability of supply.

For further example, increased coal consumption will lead directly to increased levels of small particulate pollution because, as yet, there exists no known technology for control on a large scale. According to public health experts, small particulate pollution increases the incidence of respiratory disease. This is a tradeoff too--increased reliability of supply through increased coal production is achieved and one of the expenses is diseased lungs in

an indeterminable number of persons. Finally, to what degree should supply reliability through coal development be achieved in relation to the other major alternatives--particularly nuclear power, energy conservation, and the renewable energy resources (solar, geothermal, fusion)? It is only through a consensus reached on these kinds of tradeoffs that energy decisions can be made.

WHAT ARE THE ALTERNATIVES?

The means of attaining energy policy goals have been the subject of debate in the administration, the Congress, and the Nation. Energy legislation enacted since the international oil crisis includes the Emergency Petroleum Allocation Act, the Federal Energy Administration Act, the Energy Supply and Environmental Coordination Act (ESECA), the Energy Reorganization Act, the Energy Policy and Conservation Act (EPCA), the Energy Conservation and Production Act (ECPA), and, recently, the Surface Mining and Reclamation Act of 1977 and the Department of Energy Organization Act. President Carter's National Energy Plan is a further step in the direction of identifying national energy problems, goals, and programs. All these measures constitute a partial framework in which a national energy policy can be pursued. But ultimate decisions have yet to be made concerning the role of conservation, an acceptable level of foreign oil imports, the use of coal, research and development for synthetic fuels and renewable energy resources, the long-term future of nuclear power, and the balance to be struck between the various energy policy goals--supply, environment, efficiency, foreign policy, equity, and economic development. In other words, many energy steps taken to date are in the right direction and are not inconsequential, but given the unresolved issues and the dimensions of the problem we are still very far away, indeed, from implementation of a full-fledged national energy policy.

A plethora of unresolved energy problems, such as air pollution (including the increasing carbon dioxide loads in the atmosphere), oil imports, and nuclear waste build-up, still confront us. The potential for saving Btus by more efficient end use of energy is sufficiently large that it alone could substantially reduce the magnitude of these unresolved, energy supply problems.

There are many levers available to the Federal Government if it chooses to favor a given energy option such as energy conservation. Through regulations, the Government can require that energy efficiency performance standards be met for certain products. Through the tax system, the Government can provide incentives for the installation of more energy

efficient systems. The Government can also subsidize energy conservation--through direct payments to help meet the capital costs of more energy efficient systems or through support of development and demonstration of conservation technology.

An equally wide variety of levers is available to the Federal Government if it chooses to push the coal option but at the same time gets involved directly in trying to mitigate the human, environmental, and socioeconomic costs of increased coal production. The Government could, for example, nationalize the coal industry, as most other Western industrialized countries have done. Great Britain is an example. By nationalizing the coal industry, the Government assumes direct responsibility for controlling coal's consequences and for coal's future capital investment. Whether or not the Government's relative success, if any, in this regard would be worth the tradeoff of diminished free enterprise is another matter. We have not seen evidence in our review to support such a conclusion. A variation on the nationalization approach is being tried in West Germany where the government consolidated the coal industry into three operating companies under the control of a semipublic holding company. The West German government provides substantial direct subsidies to the industry while at the same time taking part in the industry's decisionmaking process by having public representatives on all key industry executive boards.

Near the other extreme, the Government could rely solely on its tax powers to tilt the energy market in coal's favor. It could, for example, raise coal's 10 percent depletion allowance as well as raise the ceiling on the amount of income to which depletion can be applied--currently depletion cannot exceed 50 percent of a company's income. Actions such as these would make coal more competitive, though not necessarily more economical. Alternatively, it could, for example, put a \$5 tax on every barrel of imported oil, or lower the uranium 20 percent depletion allowance.

In addition, the Government could use its taxing powers to discourage adverse environmental effects on coal consumption. It could, for example, place a graduated tax on the amount of pollution emitted by utilities.

Another option the Government could take is to pay for the pollution control devices needed to make coal as competitive as possible from an environmental standpoint. Still another option, very controversial, would be to reconsider the present sulfur limitations.

The Federal Government currently relies almost exclusively upon its power to regulate in order to mitigate the consequences of increased coal production and consumption, especially in the areas of miner safety and health, air pollution, and strip mining on public lands.

At present, there are so many different Federal policies that affect coal's development, many of which seem to work at cross-purposes. It is literally impossible to say whether their net effect is to encourage or discourage coal development. For example, the Federal Government encourages coal in relation to oil or natural gas by subsidizing a greater portion of its research and development. On the other hand, the Government discourages coal in relation to oil by providing oil with certain tax advantages such as the foreign tax credit. In the opposite direction, the Government provides a substantial indirect subsidy to coal by paying a pension to miners who have contracted pneumoconiosis. This kind of back-and-forth analysis could go on and on. We do not try to address all of these options in this report, but we do attempt to deal with the more important ones.

One conclusion can be drawn. It is clear that the energy market in which we find coal today bears only the slightest resemblance to the classical economic model of a free market. For better or worse, Government decisions influence the future of this industry every bit as much, if not more, than do the individual, microeconomic decisions of the market's private sellers and buyers. Government decisions affect everything from the rate a railroad can charge for hauling a ton of coal from Montana to Chicago, to the sulfur content of coal which a Chicago utility is allowed to burn.

President Carter's National Energy Plan relies heavily on regulatory, economic, environmental, and research and development policies to stimulate expanded use of coal to help fill the growing gap created by (1) rising energy demand and (2) relatively stable or declining production of domestic oil and gas.

The administration estimates that the plan would increase the use of coal in 1985 to 1.2 billion tons. Without the plan, the administration estimates that coal production will reach 1 billion tons in 1985. The administration's plan proposes

--a regulatory program to require coal use by utilities and large industries.

--an oil- and gas-users tax and rebate/investment tax credit system to provide economic incentives to convert to coal;

--an environmental policy for using coal to minimize risks to public health and environmental damage; and

--a research program for coal conversion, mining, and pollution control technology.

These proposals are assessed in an earlier GAO report entitled An Evaluation of the National Energy Plan. 1/

Although the administration's plan deals with some of the constraints to increased coal production, it does not deal with transportation, productivity, and other constraints that will, in our opinion, make the achievement of even 1 billion tons of coal production in 1985 highly unlikely.

WHAT'S IN THIS REPORT?

This report discusses the implications of reaching coal production and use levels of about 1 billion tons by 1985 and 1.5 billion tons by 2000. Our work indicates that there are many tradeoffs that must be accepted and many problems that must be resolved to achieve these levels. Some of the tradeoffs have been pointed out above. In our earlier report to the Congress, An Evaluation of the National Energy Plan, we identified a number of problems that would need to be resolved in order to reach the coal production and use objectives of the administration. These problems include the need for

--capital to upgrade large portions of the Nation's railroads, particularly in the eastern States, together with the need to expand existing capabilities;

--congressional resolution of uncertainty concerning the issue of rights-of-way for slurry pipelines;

--improved labor relations to prevent disruptions due to wildcat strikes, together with the need for improved miner health and safety conditions, recruitment, and training;

*Note: Numbered footnotes to ch. 1 are on p. 1.14.

- greater manpower and equipment productivity;
- accelerated Federal research to determine the health and environmental effects of burning greater amounts of coal; and
- less costly and more reliable technology to control air pollution from coal burning facilities. 2/

These and other problems are discussed further in the main body of this report.

This report synthesizes existing literature and information on the coal energy supply option and addresses the areas of coal demand, resources, and production, as well as the environmental, socioeconomic, and international implications of coal development. The report is intended to be a reference document as well as an identification of the principal problems, tradeoffs, and alternatives to assist the Congress and other decisionmakers in formulating a national energy policy.

In performing the study, we researched literature on the subject and discussed coal development problems with representatives of numerous Federal agencies including the Departments of the Interior, Transportation, Labor, and Agriculture; the Energy Research and Development Administration; the Interstate Commerce Commission; the Federal Energy Administration; the Environmental Protection Agency; the Federal Power Commission; the Federal Trade Commission; and the Office of Management and Budget. We met with representatives of various State agencies, institutions of higher education, coal producers, coal mining equipment manufacturers, coal transportation companies, coal-related trade and union organizations, electric utility companies, and coal exporters. In addition, we discussed international implications of U.S. coal production with representatives of the Organization for Economic Cooperation and Development in Paris.

In the following chapters, we have used two long-term energy scenarios as analytical tools--the Bureau of Mines study, United States Energy Through the Year 2000 (Revised) 3/ and the Edison Electric Institute low-growth case from its study, Economic Growth in the Future. 4/ We also have used projections from other sources, including President Carter's National Energy Plan in some cases.

Table 1 summarizes the two scenarios we used. Comparative analysis of these projections, however, requires a strong word of caution. Each scenario was performed at different times, using different assumptions about economic growth, prices, Government policies, demand elasticities, and so on. They serve to give us a feeling of the overall parameters of expectation in this area; we do not view either of them as the "right" projection. The real world will undoubtedly fall somewhere between the two with a mix of fuel supplies and demands somewhat different than both.

These scenarios do not show regional coal supply and demand projections, but rather present gross national numbers. For purposes of our study, we wanted to disaggregate the gross numbers on a regional basis. For this regional analysis, we assumed that (1) all future mine openings and additions projected by the coal industry up to 1985 would actually occur, (2) the coal required to be replaced from mine retirements for the period 1975-1985 would total 137 million tons, and (3) heat content for all coal mined in a particular State would remain constant. Industry data on coal mine expansion is not available after 1985. To make projections for the year 2000 under these circumstances, we further assumed that (1) any necessary deletions or additions required to meet the scenario levels in 2000 would be made based upon each State's proportional contribution to the estimated total U.S. mining capacity in 1985 and (2) the proportion of underground and surface coal production would remain at the same level after considering all mine capacity additions and deletions in 1985.

For coal demand in the electric utility sector, we assumed that (1) all plants which were designed to use coal as a boiler fuel would use coal, (2) new plants will come on-line as scheduled, (3) plant retirements will occur at an annual rate of 2.5 percent, (4) 1975 heat rates, i.e., Btus required to produce 1 Kilowatt hour of electricity, for geographic regions will continue, (5) coal-fired plants will continue to operate at 46 percent capacity in 1985, but in 2000, capacity utilization will increase to 60 percent, and (6) any necessary additions required to meet scenario levels in 2000 will be made based upon each region's proportion of the new total additions during 1975-85.

Table 1

Comparison of Energy Forecasts

<u>Forecast</u>	<u>Domestic coal consumption</u>	<u>Domestic oil</u>	<u>Oil imports</u>	<u>Domestic natural gas</u>	<u>Natural gas imports</u>	<u>Nuclear</u>	<u>Other (note b)</u>	<u>Total United States consumption</u>	<u>Coal export</u>
-----Quadrillion Btus----- (note a)									
1974 Base Year	13.1	20.3	13.1	21.0	1.0	1.2	3.3	73.0	1.7
<u>1985</u>									
Bureau of Mines	21.3	29.3	16.3	18.8	1.3	11.8	c/4.7	103.5	2.1
Edison Electric Institute - low growth case	16.3	32.8	10.4	21.0	6.6	d/14.2	(d)	e/101.2	2.1
<u>2000</u>									
Bureau of Mines	34.8	27.4	23.8	17.0	2.6	46.1	c/11.8	163.4	2.8
Edison Electric Institute - low growth case	19.5	32.4	7.1	14.7	3.2	d/32.5	(d)	109.5	2.8

a/ British thermal units.

b/ Includes geothermal, oil shale, and hydropower.

c/ Solar energy not forecast.

d/ Estimates of hydropower and other sources are included with nuclear.

e/ Does not add due to rounding.

In this report, we attempted to standardize our reporting on a three-region geographic basis--Eastern, Central, and Western. When we began to accumulate our source information, however, we discovered that a consistent presentation was not entirely possible because the source data included diverse geographic areas--one State only, Southeastern Appalachian States, Rocky Mountain States, or other combinations. In cases where the source data permits, we present the information on a three-region basis; otherwise, we present the information as it was originally developed.

In preparing this report, we received comments from a varied group of consultants knowledgeable about coal and related areas. This diverse group included individuals in the fields of economics, finance, and geology as well as those with experience in coal production and environmental matters.

A draft of this report was reviewed by various Government organizations. Their formal comments have been recognized in finalizing the report. The organizations include:

- Department of Labor.
- Department of the Interior.
- Department of Transportation.
- Department of the Treasury
- Energy Research and Development Administration.
- Environmental Protection Agency.
- Federal Energy Administration.
- Federal Power Commission.
- Interstate Commerce Commission.
- Tennessee Valley Authority.
- Office of Management and Budget.
- Department of Commerce.

In the chapters which follow, we first discuss the demand for coal in the various economic sectors. This is followed by an analysis of coal reserves in chapter 3. The next two

chapters present data on coal supply and methods for transporting it to relevant markets. Chapters 6 and 7 discuss the environmental and socioeconomic constraints associated with coal usage and supply. Chapter 8 discusses U.S. coal in foreign trade. Chapter 9 presents the principal conclusions of the report. Several special considerations are discussed in the appendices.

FOOTNOTE REFERENCES

- 1/United States General Accounting Office, An Evaluation of the National Energy Plan, EMD-77-48 (Washington: U.S. General Accounting Office, July 25, 1977), Chapter 5.
- 2/Ibid., p. 5.1.
- 3/Walter G. Dupree, Jr. and John S. Corsentino, United States Energy Through the Year 2000 (revised) (Washington: Government Printing Office, 1975), pp. 1-65.
- 4/Edison Electric Institute, Economic Growth in the Future (New York: McGraw Hill, 1976), pp. 147-169.

CHAPTER 2

HOW MUCH DO WE NEED?

Energy fuels serve two separate categories of needs. A consideration of these needs (along with the types and forms of fuels suitable for them) is necessary to form a reasonable projection of the demand for coal and the capability of coal to supply energy needs under present and expected conditions.

One category of fuel need involves the transportation sector--automobiles, trucks, railroads, airplanes, and ships. Coal once fueled some of these transportation modes, but no longer does. Synthetic liquid fuel from coal is not a likely short-term reality, but may be a source of transportation fuel in the future. There are some other potential opportunities for coal in this category, in the form of electrified mass transit systems and the electric automobile.

The second need category is for stationary combustion plants, such as electric utility generating stations, and commercial and industrial heating systems. In this area coal has the capability to replace oil and natural gas--to some extent in existing plants, but more importantly for new growth.

This chapter focuses on determinants and opportunities for greater coal demand between now and 1985, and 2000. It considers future demand as assumed in two scenarios selected for analysis, as well as the future demand assumed in the National Energy Plan.

In relative terms, coal demand has been declining for more than half a century. ^{1/} Even as late as 1950, coal supplied 20 percent of energy in the transportation sector, 36 percent in the household/commercial sector, and nearly 50 percent of fuel in the industrial sector. ^{2/} However, by 1975 coal was no longer a significant factor in either the transportation or household/commercial sector, and its share of the industrial sector was 22 percent and apparently declining. ^{3/} In the meantime, coal's share of the electrical sector equalled roughly 44 percent, down from 53 percent a

Note: Numbered footnotes to ch. 2 are on pp. 2.47 to 2.53..

decade earlier.* 4/ Despite this historical trend away from coal, many policymakers view coal as a major substitute for other fuels, particularly imported oil.

What are the determinants and opportunities for greater coal use? These matters are discussed in the following four sections:

- A perspective on coal use in the overall energy market.
- Substitution of coal for other fuels in the electrical sector.
- Substitution of coal for other fuels in other sectors, through direct burning and synthetic fuel development.
- Implications of coal use for widely different energy needs and use patterns.

The discussion on fuel substitution focuses on the possibilities of increased coal use in various sectors of the economy, leaving for later discussion the implications of varying overall energy needs. The section on the electrical sector has two main parts. The first focuses on what appears possible regarding short-term increases in coal energy inputs. The second part examines present planning for coal use over the next decade or so. The discussion in this and other sections emphasizes prospective coal use in the period to 1985, though we do consider some developments to 2000. This emphasis on the next eight years principally reflects the state of available knowledge and data.

In the third section, we discuss the implications of coal for diverse energy needs and use patterns and we note that past efforts to forecast these patterns have not been very successful. The purpose of this section, however, is not to predict, but rather to explore the possible range of coal use patterns in the context of varying energy needs. To do this, we chose scenarios for consideration which vary widely in terms of total energy growth, as well as in the mix of fuel supply.

Our main observation is that coal use will increase significantly in absolute terms due to the expanding energy market but it may not gain a larger percentage share of that market than it now has. Present and prospective

*Of course, in absolute terms, coal experienced modest growth, especially in the electrical sector.

circumstances do not inevitably lead to greater relative coal use. While coal is comparatively inexpensive in terms of heat content, the true economic cost of burning coal must take into account the costs of transportation, distribution, handling, and pollution control.

Thus far, decisionmakers and forecasters have been acting as if a shift to coal from other fossil fuels may not occur. To change this outcome, substantial changes are needed in coal's relative attractiveness as an energy input. Over the next decade or so the chief determinants of coal use for electrical power generation will be (1) pollution control costs and (2) development of cheaper, more flexible transportation of coal in raw form or as electricity, etc. In the longer perspective the potential for further coal development will depend on whether it can be economically manufactured into gas or liquids. Such technological improvements would have dramatic consequences for coal demand in both the intermediate and longer terms. A consensus of energy forecasts, however, reflects doubt that such developments will occur. For the period beyond 1985, the most important variables affecting coal demand are the rate and direction of technological changes for coal and the competition with nuclear power, not the trend in total energy needs.

A PERSPECTIVE ON COAL USE IN THE OVERALL ENERGY MARKET

Coal is by far our most plentiful fossil fuel energy source under present technological capability. Oil shale is plentiful but not usable with existing technology. For the next several decades coal and nuclear energy offer the best hope of reducing our dependence on overseas energy sources, and of conserving our dwindling supplies of natural gas and petroleum for uses to which they are today uniquely suited. However, there are disadvantages to the greater use of coal, and some believe for environmental and health reasons that every effort should be made to restrict its use.

To determine the probabilities of how great the demand for coal will grow in the next decade and beyond, it is helpful to examine the factors which have influenced choices between competing fossil fuels--coal, oil and natural gas--in the past, and then to determine to what degree each of these factors will contribute to fuel decisions under current economic, environmental, social, and international conditions.

It is also necessary to compare the extent of demand fluctuations between these fuels in recent years, and to study the relationship which each has to the other--both in total demand and in the competitive process.

Coal was the initial fuel (after wood) for stationary uses, as it was also for running railroads and steamships, and it retained its dominance until about the end of the first third of the twentieth century. Then, for various reasons, a rather massive movement toward residual oil for large furnaces and steam turbines, to distillates or light heating oil for homes and other small heating plants, diesel oil for railroads, and natural gas for everything from residential/commercial heating to industrial and utility use took place from the end of World War II through the 1960s.

All in all, the demand for coal, once the Nation's principal energy source has been declining relative to other fuels for about half a century. Why did this happen?

The causes for coal's relative decline include the development of means to capture and transport cleaner and more convenient fuels, notably natural gas, and the demise of both coal-fired locomotives and furnaces in residences. However, these events may merely be symptoms of a more fundamental deficiency of coal.

Coal is the least convenient fossil fuel. It is bulky, causing difficulty in handling, storing, or transportation. It creates problems when extracted and when burned. Indeed, efforts to develop coal slurry pipelines and make synthetic fuels from coal can be viewed as attempts to make coal as much like oil and gas as possible. Aside from use in metallurgical production processes, coal will be consumed only when its costs are sufficiently below those of other alternative fuels to outweigh its disadvantages, or when the national interest clearly requires it as against greater use of foreign oil and scarce domestic oil and gas. 5/

In the last several decades, coal use has become progressively more concentrated in the electric utility sector, as shown in table 1. Table 1 shows some other interesting features in the part that coal has played in the Nation's energy picture. Domestic demand for coal dropped to less than 400 million tons by 1960. However, because of rising needs for electric generation during the past 15 years, with coal still the favored fuel in that sector, total domestic demand rose steadily from 398 million tons in 1960 to above 600 million tons by 1976. In this same period, total utility coal demand climbed from 179 million tons to 457 million. However, as shown in table 2, coal's total share of the utility market declined from 52 percent in 1960 to 44 percent by 1975. Also, referring back to table 1, coal's share of the total U.S. energy market declined from 38 percent in 1950 to 23 percent in 1960 and to 19 percent in 1976.

Table 1

Domestic Coal Consumption--1950-76

	<u>1950</u>	<u>1960</u>	<u>1970</u>	<u>1973</u>	<u>1975</u>	<u>1976</u>
	----- (million tons) -----					
Total domestic coal demand	494	398	524	562	561	602

Demand by User Sectors

<u>Electric utilities</u> (tons)	93.9 19%	179.2 45%	234.9 62%	387.8 69%	415.1 74%	457.5 76%
<u>Other steam</u> (tons)	(a)	127.4 32%	94.3 18%	73.1 13%	56.1 10%	54.2 9%
<u>Metallurgical</u> (tons)	(a)	87.6 22%	99.6 19%	101.2 18%	89.8 16%	90.3 15%

Coal's Share of Total U.S. Energy Use

	----- (Percent) -----					
All uses (note b)	38	23	19	18	18	19

a/Not available.

b/Exports not included.

Currently, more than 70 percent of all domestic coal consumption is used as boiler fuel for electric power generation. It is the single most important fuel in the electrical sector. Even here, however, its position has not been uncontested.

During 1962-69, the average cost of fossil fuels to utilities exhibited a downward trend relative to the general level of prices. During this period coal enjoyed approximately a 23 percent cost advantage over oil. ^{6/} Despite this advantage, nearly 29 thousand megawatts (MW) of coal-fired capacity was converted to oil during 1965-72. ^{7/} Furthermore, during the 10-year period ending in 1973, less than one-third of new electrical generating capacity was coal-fired. ^{8/} In

general, the shift to residual fuel oil* was greatest after 1966, when import controls were effectively removed on the East Coast.** 9/

The relative decline of coal use in the electrical sector is summarized in table 2. Even in absolute terms, total coal consumption grew by only 67 million tons during 1950-75, 10/ an annual growth rate of only 0.49 percent.

Table 2

Electric Generation by Energy Source

	<u>Coal</u>	<u>Nuclear</u>	<u>Oil</u>	<u>Gas</u>	<u>Hydro/other</u>
	----- (Percent of total Btus) -----				
1955	52.8	-	7.3	18.1	21.3
1960	51.5	-	6.8	21.6	20.1
1965	52.8	0.3	6.5	21.6	18.6
1970	44.7	1.4	12.9	24.7	16.3
1975	44.0	8.2	16.4	15.8	15.6

Coal, therefore, entered the 1970s being seriously challenged in its most important remaining market. The challenge was three-pronged: (1) other fossil fuel prices were stable or trending downward relative to coal, (2) stringent air pollution control requirements were being developed which increased total user cost when burning coal, and (3) large-scale nuclear installations appeared to offer significant cost-savings for baseload electric power generation.

The oil price revolution of 1973-74, along with increasingly difficult circumstances involving the use of natural gas as a boiler fuel for power generation,

*Residual fuel oil is the main type of oil product used by utilities.

**The switch after removal of import controls may have reflected, in part, apparent trends toward stricter clean air standards.

appears to be reducing two threats to continued coal use. The extent of coal's future as an energy source is still uncertain, however. In the next decade or so, as in the recent past, its future rests primarily on developments associated with electric power generation and consumption. Continued or increased acceptance of coal as an energy input will hinge on the cost of making it environmentally acceptable in terms of current and prospective standards and how these costs compare to costs associated with other electric generation options.

The most severe current environmental challenge to coal use relates to the control of sulfur oxides. Coal burning powerplants account for as much as one-half of all sulfur oxides emitted nationally. No easy control techniques are available. Stack gas scrubber technology is advancing slowly. Increased reliance on low-sulfur coal has shifted some demand from traditional producing centers, in the East and Midwest, to new mines in the West. Currently, however, nearly 50 percent of all coal consumption for powerplant use is out of compliance with existing clean air standards. 11/

Current coal costs for power generation compare very favorably with those of oil. Data in table 3 show that in 1973, coal cost one-half as much as fuel oil in the electrical sector. Although gas had been even cheaper than coal, except for the major gas producing States few utilities were able to obtain gas for use as a boiler fuel. Price movements since 1973 appear to favor coal even more.

These developments, however, are seriously affected by user costs associated with environmental control. It is estimated that when costs of adapting to prospective environmental requirements are taken into account, true costs of coal use per million Btus may be increased by about 26 percent. 12/ Hence, the price data in table 3 may overstate the relative cost advantage of coal.

Table 3

Relative Fuel Costs to Electric Utilities
1973-76 (note a)

<u>Fuel</u>	<u>1973</u>	<u>1974</u>	<u>1975</u>	<u>1976</u>
----- (1975 cents per million Btus) -----				
Coal	52.7	77.4	81.4	81.0
Oil	104.4	209.5	202.0	191.0
Gas	43.9	52.4	75.4	98.8

a/ Fuel prices converted to 1975 values on the basis of changes in the Wholesale Price Index for commodities.

SUBSTITUTION OF COAL FOR OTHER FUELS
IN THE ELECTRICAL SECTOR

Short run opportunities

The preceding section noted the importance of the electrical sector when considering fuel substitution possibilities. Even in the short-term there may be substantial opportunity. One month preceding the Organization of Petroleum Exporting Countries (OPEC) oil embargo, the Federal Power Commission (FPC) was optimistic about the utilities' ability to convert from oil to coal in an emergency:

"It appears that the nation's electric power generating industry could, within three weeks, absorb a cut in residual oil supply of perhaps 2.2 million barrels per week (annual rate of 114 million barrels equivalent to 18.9 percent of 1972 residual oil imports) and at the end of one year 3.8 million barrels per week (annual rate of 198 million barrels equivalent to 31.0 percent of 1972 residual oil imports)." 13/

Shortly thereafter, the Congress passed the Energy Supply and Environmental Coordination Act (ESECA), with an expiration date of June 1975, evidently presuming a 1-year conversion program to be adequate. The act

has been renewed twice. As of December 1976, 74 conversion orders had been issued by the Federal Energy Administration (FEA). Only 11, however, have received approval by the Environmental Protection Agency (EPA) and only three plants have been converted. Fifty-one orders have been stayed pending the installation of improved pollution control equipment.

Table 4 shows that the FPC originally estimated that some 23.7 thousand MW of electric generating capacity could eventually be converted. 14/ In its April 1976 report to the Congress, FEA estimated that as much as 20.4 thousand MW could be converted by June 30, 1977. 15/ This would have represented about 0.5 percent of total generating capacity scheduled to be operative in early 1977. 16/ In fact, as of July 1977, only three utility powerplants with 158 MW of capacity had been issued final prohibition orders.* 17/ Nonetheless, table 4 also shows that--if the conversions do eventually occur--the Nation will save about 151 million barrels of oil while using an additional 47 million tons of coal per year. 18/ Since utilities used 404 million tons of coal in 1975, 19/ the impact of the ESECA orders affecting existing plants would be to raise utility coal use about 12 percent.

*In effect, a prohibition order means a utility is prohibited from burning any fossil fuel except coal.

Table 4

Anticipated Impact of Orders to Convert
Existing Oil-Fired Powerplants to Coal

Impact and cost of existing
utility powerplant conversions (note a)

	<u>Estimated January 1973</u>	<u>Estimated April 1976</u>
Megawatts (thousands) of oil-fired capacity convertible to coal		
within one year	21.1	-
Total	23.7	<u>b/20.4</u>
Oil savings (million barrels per year)		
within one year	178	-
Total	198	151
Additional coal required (note c) (million tons)		
within one year	68	-
Total	74	47
Conversion cost (millions of 1975 dollars) (note d)	<u>e/\$ 137</u>	\$1,270

- a/Conversion results and costs estimated in April 1976 for conversions to be achieved by June 30, 1977.
- b/Includes conversion of gas-fired plants.
- c/Includes coal required for powerplants converted from gas to coal.
- d/Converted to 1975 dollars with Wholesale Price Index for Materials and Components for Construction. Economic Report of the President, January 1977, p. 249.
- e/During 1965-72, 28,785 MW of coal-fired capacity were converted to oil. Of this capacity, the FPC estimated that 22,704 MW could be reconverted to coal eventually. The data presented in the table include all plants believed convertible to coal, whether they were initially coal-fired or not. However, the 1973 cost estimate pertains to the 22,704 MW estimated as reconconvertible to coal and the 1976 estimate to cumulative eventual cost.

ESECA calls for conversion where practical from both an air quality and cost standpoint. Unfortunately, the estimated costs of conversion have increased from \$137 million to \$1,270 million, or about 850 percent. A principal contributor to these costs is the need for pollution control equipment. Of course, these conversion costs may be partially offset by lower fuel costs. Total offset is unlikely, however, and the estimated \$1,270 million capital cost for conversion works out to \$63 per kilowatt (kw) of generating capacity. This compares with estimated construction costs for new coal-fired plants of \$360-480 per kw. 20/

The initial FPC estimates pertained almost exclusively to powerplants originally designed to burn coal. As concern about natural gas use in boilers heightened, some urged that natural gas boilers also be subject to conversion orders.

About 70 percent of all gas used as a utility boiler fuel occurs in the South Central States*, which accounts for nearly 90 percent of total U.S. gas production. 21/ An investigation of conversion opportunities revealed that while utilities in this area derived 99 percent of their fuel-generated electricity from gas in 1970, reliance had been reduced to 87 percent by 1975 22/, and a further 40 percent reduction by 1985 was already scheduled. 23/ In fact, by 1983 the baseload generating capacity in this area is expected to be completely coal and nuclear.

Efforts to accelerate conversion appear to be very costly. For example, assume that all gas and oil boilers were discontinued, effective January 1, 1985, and replaced with new coal-fired capacity instead of the roughly 70 percent reduction presently scheduled. 24/ For the Southwest Power Pool Area of Texas alone**, this would increase annual generation costs more than 34 percent by 1985; cumulative investment costs would rise by approximately \$4 billion.

*Defined for purposes of this section as consisting of Arkansas, Kansas, Louisiana, Oklahoma, and Texas.

**This comprises about one-fourth of the area in Texas. The bulk of the State is represented by the Electric Reliability Council of Texas.

Also under ESECA there is a program dealing with new powerplants. Under this program new powerplants are required to have the capability of burning coal as a primary energy source. By June, 1977, over a hundred such orders (construction orders) have been issued, affecting over 50 thousand MW of capacity. 26/

Although this sounds impressive, these figures may not be meaningful since many utilities might have elected such coal-firing capability anyway, because of gas curtailments and higher oil prices. Hence, the extent to which the ESECA program has had an impact here remains uncertain. The estimates, therefore, presented in table 4 exclude consideration of the program related to new powerplants.

In summary, the ESECA program to convert existing powerplants (prohibition orders) to coal has thus far not lived up to expectations. The principal reason is the inability of utilities to burn coal in these plants so as to comply with clean air standards. Such compliance would appear, in many cases, to result in substantial conversion costs. Furthermore, acceleration of conversion to coal from gas would seem to impose substantial burdens on electricity consumers in affected States such as Texas.

A potentially more attractive means of substituting coal (and nuclear) for oil or gas involves improved load management. 27/ For purposes of the present discussion, load management is defined broadly to include two phenomena often considered separately. The first embodies the usual definition of load management: the leveling of the load curve of an individual utility to make more efficient use of existing equipment. Improved load management here could involve adoption of some new technologies. However, the principal change would involve greater use of differential electric rates for peak and off-peak periods. For all retail users, this could mean higher rates in one season (e.g., summer) than in others. For large retail users, this could mean higher rates during certain hours of the day (e.g., 3-6 p.m.) than at other times. Rate schedules such as these have been common in Great Britain and France for many years and are becoming more prevalent in the United States. 28/

Were these and other load management techniques adopted, greater relative use of baseload electrical generating equipment would result. Since baseload

equipment is largely coal-fired at present (versus oil or gas-fired for peaking equipment) 29/, greater use of load management techniques would lead to substitution of coal for other fossil fuels.*

The second form of load management power pooling, is broader in scope, and is in considerable use now. At the level of retail sales, it involves several utilities, often organized into a power pool, attaining maximum coordination through organization devices such as a central dispatch. At the level of wholesale sales, it involves more exchanges and sales of power, even among widely separated utility groups. And, in general, load management in this sense involves full coordination, interconnection, planning and use of electric generating facilities with a view to augmenting capacity utilization. 30/ Ultimately, improved load management of this type would likely lead to expansion of the wholesale market.

If the capacity factors of baseload generating equipment could be raised through these two types of load management, substantial substitution of coal for other fossil fuels could result. However, the basic questions are: how much substitution and how soon?

While definitive answers to these questions are not possible, some rough estimation is. Consider the stock of coal-fired electric generating equipment in place and scheduled to be operative by 1985. Surveys by the National Electric Reliability Council (NERC) estimate this coal-fired capacity at 320 thousand MW by 1985 (versus 798 thousand MW in total). 31/ To generate this amount of electricity, NERC estimates that utilities would use 827 million tons of coal by 1985. 32/

The potential increase in coal consumption which would result from improved load management at the retail level is hard to estimate. However, FEA has calculated that more effective load management, at the retail level alone could increase utility usage of coal by 52 million tons by 1985. 33/ The potential for the second type of load management (power pooling) discussed above is even more difficult to determine. However, it is worth noting that seven Eastern

*There would also be substitutions of nuclear power for electricity from oil- and gas-fired plants because nuclear powerplants are exclusively baseload.

Reliability Council Regions are currently capable of exchanging substantial amounts of electricity. 34/ Such capability was important in January, 1977, as evidenced by the export of 548 million kilowatt hours (kwh) from the Mid-Atlantic area to other utilities. 35/ Similarly, West Virginia in 1974 produced 61.5 billion kwh electricity while needing only 18.4 billion kwh for its own use.* Hence, over 43 billion kwh were exported from this one State alone. 36/ Assuming 1974 fuel rates, 37/ this means an "export" of 45 million tons of "coal by wire" from West Virginia alone.** In fact, one estimate suggests savings of almost one million barrels per day (bpd) of oil could be achieved by 1983 were full use of "coal by wire" made. 38/

Savings of one million bpd of oil would yield a coal equivalent of about 267 thousand tons per day or about 97 million tons of coal per year.*** If this is added to the 52 million tons estimated by FEA, the total from both types of load management is about 149 million tons per year.

Thus far, the discussion has been in terms of using more coal and less of other fossil fuels. The increased coal usage necessarily leads to a concern with environmental and socioeconomic effects, as discussed in chapters 6 and 7.

Yet, the equivalent of substitution of coal for oil or gas could possibly occur without completely offsetting increases in coal use. Such an outcome might be attainable with improvements in the conversion efficiency of electrical generating equipment.

At present electrical generation is characterized by the conversion of over 10,000 Btus of energy into one kwh of electricity. 39/ Since a kwh is normally rated at 3,412 Btus, 40/ electrical generation wastes two-thirds of the

*In 1975, the United States consumed 1,876 billion kwh.

**This represents about 12 percent of 1974 utility coal consumption.

***This assumes 6.3 million Btus per barrel of oil and 21.7 million Btus per ton of coal.

gross energy input.* In any event, the conversion process is usually summarized in terms of the heat rate, which is an index of thermal efficiency defined as the number of Btus of energy input needed to generate one kwh of electricity. Measured in this way, the heat rate has been approximately constant for some 20 years. 41/

Nevertheless, a recent Edison Electric Institute (EEI) study projects improvement in the future course of heat rates for baseload generating equipment as follows. 42/

Heat Rates of Electrical
Generating Plants (Btus per kwh)

	<u>1975</u>	<u>1985</u>	<u>2000</u>
Coal	10,575	9,575	9,250
Nuclear	10,660	10,400	10,000

Such improvement is conceivable, given the incentive to cut fuel costs engendered by the recent increases in fuel prices. But such improvements are by no means inevitable and since such improvements would be confined to new plants, the overall rate of improvement depends on the level of new powerplant construction. In any event, heat rate improvements of the magnitude suggested by EEI imply potential coal use savings of as much as 150 million tons per year by 1985.**

Unfortunately, we do not know how much such improvements would cost. Current research efforts along these lines by the Energy Research and Development Administration (ERDA) seem modest. It would appear that a potential exists to simultaneously increase reliance on coal as a fuel by improving the efficiency of its use at the same time reducing the rate of depletion of this resource.

*Similar efficiency losses occur with more direct use of fossil fuels, but are less easily measured.

**This estimate results from a comparison of the actual 1974 fuel rate with that projected by EEI for 1985. The fuel rate is defined as the number of pounds of coal required to generate one kwh of electricity.

Table 5 summarizes key quantitative aspects of the preceding discussion. Significant opportunities exist for shifting from oil to coal in the electrical utility sector even without a major change in the basic structure of the generating base. These opportunities can be achieved, however, only in conjunction with changed electrical marketing practices both at the retail and wholesale level.

Were all three actions in table 5 to occur by 1985, the net effect would be to raise utility coal consumption by only 46 million tons. Adding this to the NERC estimate of 827 million tons, however, results in utility coal consumption of 873 million tons, which is more than double 1975 consumption by utilities.

Nonetheless, this amount of coal usage by utilities is uncertain because the demand for electricity may not increase as much as expected by NERC.

The National Energy Plan promotes adoption of load management techniques, particularly at the retail level. GAO supports the efforts to improve the rate structure of electric utilities. The administration's proposal is predicted to save about one million barrels of oil equivalent per day in the electrical sector. This compares with the projected savings of 1.8 million barrels of oil equivalent per day in table 5. The largest source of the difference appears to be the savings which may be obtainable, at least in part, through better load management at the wholesale level.

Table 5

Additional Consumption of Coal by Utilities in 1985
Under Alternative Actions

<u>Action</u>	<u>Additional usage</u> <u>of coal (note a)</u>		<u>Equivalent savings</u> <u>in oil (note b)</u>	
	<u>Tons</u> <u>(millions)</u>	<u>Percent</u> <u>of 1975</u> <u>usage</u>	<u>Millions</u> <u>bpd</u>	<u>Percent</u> <u>of 1975</u> <u>imports</u>
Full conver- sion of utility powerplants	47	12	0.4	7
Optimal load management	149	37	1.4	23
Maximum thermal efficiency	(-150)	-	-	-
Net effect	46		1.8	

a/The additional coal usage from conversion is an FEA coal estimate. The other two sources of additional coal use are GAO estimates based on EEI estimates of fuel rates and NERC estimates of electrical generating capacity.

b/For purposes of this computation coal was evaluated at 21.7 million Btus per ton and oil at 6.3 million Btus per barrel.

Long-term opportunities

Under current and foreseeable cost and other conditions, little oil or gas will be used for baseload generating of electricity.* Hydroelectric sites are less plentiful and geothermal generation is likely to be important--if at all--only in California. Hence, the contest for baseload generation for the next 25 years is between coal-fired and nuclear-powered plants.

*New England may be an exception. In addition, delay in construction and operation of nuclear plants may necessitate greater use of oil or gas in areas such as New England or the southwestern, gas-producing States.

Current industry plans for electrical generating equipment are summarized in table 6. ^{43/} In terms of capacity, coal-fired plants are expected to increase modestly in relative importance. Announced decisions on new capacity indicate coal's share will rise from 38 percent in 1975 to 40 percent in 1985. During this same period, nuclear's share is projected to rise almost threefold. Beyond 1985, present plans indicate an even greater relative reliance on nuclear. To the extent that announced utility expansion plans are indicative, nuclear and coal are viewed as the significant energy sources of the future for baseload electric power generation.

Announced utility expansion plans, however, have not materialized. For example, of the 21,272 MW scheduled to be placed in service during April 1 through September 30, 1976, only 12,505 MW were actually placed in service. ^{44/} Furthermore, nuclear units accounted for more than one-half of the uncompleted capacity in MW. ^{45/} In contrast, over 80 percent of the coal-fired units scheduled for commercial operation during April 1 through September 30, 1976, were actually entered into service during that period. ^{46/} This recent experience suggests that predicting the future role of nuclear power presents special complications, a subject discussed below. The best data available at this time, however, indicate that both coal and nuclear power will become increasingly important during the next 25 years.

Table 6

Currently Scheduled Generating Capacity
by Major Fuel Category, 1975-95

<u>Fuel Category</u>	<u>1975</u>	<u>1985</u>	<u>1995</u>
	(Percent of total mw capacity)		
Coal	38.5	40.2	(a)
Total fossil	69.7	60.2	50.3
Nuclear	7.7	21.2	33.9
Hydro	13.0	10.4	8.0
Other (note b)	9.6	8.2	7.8

a/Not available.

b/Includes peaking, which is also fossil fuel.

Despite recent indications that nuclear is unlikely to live up to earlier expectations, current utility plans are still predicated on expansion of nuclear power relative to expansion of coal-fired generation. Even in those areas in which coal is mined and plentiful, utilities appear to be electing the nuclear option. For example, the utilities in two midwestern Electric Reliability Councils, ECAR* and MAIN**, are located above the coalfields of northern Appalachia and the Midwest. Yet more than half the capacity additions scheduled by these utilities for 1986-95 are nuclear, as shown below in table 7. 47/

Table 7

Capacity Mix as a Percent of Total Capacity Additions,
Selected Fuels and Reliability Councils, 1976-95

	<u>1976-85</u>	<u>1986-95</u>	<u>1976-85</u>	<u>1986-95</u>
<u>Fuel</u>	<u>ECAR</u>		<u>MAIN</u>	
	(Percent of total capacity additions (note a))			
Coal	57	(b)	38	(b)
Total fossil	61	46	53	45
Nuclear	37	51	47	55
Other	2	3	-	-

a/Data for 1976-85 are net additions.

b/Not available.

What determines the choice between coal and nuclear? Generally, utilities choose the least costly method of generating electricity. The relative importance of major cost categories are indicated by the data in table 8. 48/

*East Central Area Reliability Coordination Agreement
(Illinois plus parts of Wisconsin and Missouri).

**Mid-America Interpool Network (Michigan, Indiana, Ohio, Kentucky, West Virginia, plus parts of Pennsylvania, Maryland, and Virginia).

Table 8

Projected Costs for Baseload Plants in 1985 (Mills/kwh)

<u>Cost category</u>	<u>Plant type</u>		
	<u>Nuclear</u>	<u>Low-sulfur coal without scrubber</u>	<u>High-sulfur coal with scrubber</u>
Capital	13.5	9.3	11.7
Operating & maintenance	<u>a/1.8</u>	2.0	3.5
Fuel	<u>3.0</u>	<u>10.1</u>	<u>6.9</u>
Totals	<u>18.3</u>	<u>21.4</u>	<u>22.1</u>

a/This estimate does not include costs of waste disposal or decommissioning.

Nuclear apparently is three mills cheaper than coal plants without scrubbers and nearly four mills cheaper than coal plants with scrubbers, a cost advantage of 15 to 20 percent. Individual components of cost differ markedly. Nuclear generation is substantially more capital intensive than is coal-fired generation even with scrubbers. The assumed advantage of nuclear has been in projected fuel costs of only one-third to one-half those incurred with coal-fired generation.

All of these costs are, of course, projections. That is, they reflect best estimates of the comparative future costs of alternate means of baseload power generation. Lately, increasing doubts have been raised regarding the superiority of the nuclear option. These doubts concern costs of waste disposal and decommissioning, and the risks of fuel reprocessing and the fast breeder reactor.

To better understand the nature of the planning process in the electrical sector and of the nuclear versus coal investment decisions, GAO interviewed 12 of the largest private and public electric utilities in several major sections of the country. These utilities were asked a variety of questions, but the principal ones concerned their perception regarding interfuel substitutability.

Specifically, utilities were asked to compare alternative types of powerplants expected to be operational in 1985. The comparisons were made in terms of annual costs per kwh for three classes of costs--operating and maintenance, fuel costs, and capital.

In general, the view expressed was that only improbable large changes in projected costs would significantly alter current decisions for nuclear generation. For example, it was stated that either nuclear fuel costs would have to more than double or coal prices would have to fall by at least one-half to shift the balance in favor of coal. Alternatively, it was noted that nuclear capital costs would have to rise 40 percent or more relative to coal for the nuclear advantage to disappear.

Recent developments seem to suggest, however, that wide shifts in the comparative costs of nuclear versus coal may not be as improbable as our interviews seemed to indicate. In 1976, FEA estimated the cost of a nuclear powerplant as \$550 per kw. ^{49/} Now the cost is higher because the construction time for coal-fired plants remains at about five years. In contrast, for nuclear plants it has increased from eight to ten years. Another recent shift is in the cost of uranium versus the cost of coal. In 1974 the average price for uranium was \$7.90 per pound. ^{50/} Since then, projected prices under new contracts have increased sharply. ^{51/} In contrast, the price of coal has not changed much (table 3). In summary, substantial changes in relative costs could occur, especially since the relevant time horizon is to 1985--and beyond.

Further doubts about the accuracy of projected nuclear costs have been noted in a recent study by the Council on Economic Priorities (CEP). The earlier comparative cost estimates (table 8) assumed plant capacity factors for both nuclear and coal plants to average 70 percent. ^{52/} Actual experience in recent years has not supported this expectation for nuclear. Operating rates have, in fact, equalled only 58 percent. ^{53/} The CEP believes current experience is indicative of the future and that nuclear plants will have as much as 15 percent operating disadvantage when compared to coal-fired facilities. Should this be true, coal may prove to be a superior choice in future baseload investment decisions. Of course, if coal-fired plants are required to have scrubbers, their capacity usage may be less than that of conventional coal-fired plants.

This disappointing experience may have contributed to the recent trend toward deferral of completion dates for nuclear units. During October-December 1976, deferrals of commercial service for electric generating units amounted to 7,727 MW of capacity. 54/ Of this, 4,507 MW was nuclear steam. 55/

Though the outcome is still uncertain, the contest between nuclear and coal-fired plants is getting closer. In recent months, there has been increased awareness that previous estimates of the costs of nuclear power such as those in table 8, have been too low. A sellers' market exists in uranium; the price of Government enrichment facilities is expected to rise as ERDA changes its costing procedures; reactor design changes may contribute to further capital cost increases; and, perhaps most significantly, decommissioning and waste disposal costs appear likely to increase. For these and other reasons, recent orders for nuclear reactors have declined dramatically.

The potential seriousness of the decline in orders for nuclear reactors is highlighted by a comparison of the most recent FPC estimates and those projected by the Atomic Energy Commission (AEC) only three years ago. In 1974, the AEC had predicted an increase of nuclear capacity to 127 thousand MW by 1980. 56/ Yet, in March 1977, the FPC estimated that nuclear capacity would be only 77 thousand MW by 1980. 57/ However, the actual 1976 nuclear generating capacity was 1.6 thousand MW less than that predicted by NERC in June 1976. 58/ In contrast, during 1976, utilities' orders for fossil fueled plants were virtually all for coal-fired plants and none of these orders were cancelled.

Changing investment decisions regarding new baseload units are currently subject to the combined interaction of three factors. The first relates to downward revisions in near- and long-term electrical demand. The second involves increasing uncertainties regarding environmental hazards associated with new plant installation. These uncertainties surround both nuclear and coal-fired plants. A stellar example regarding the latter involves the recent cancellation of the 3000 MW Kaiparowits project. The third involves the prospective comparative economics of coal versus nuclear. The data in table 9 raise questions about the validity of FPC estimates of plant capacity additions presented earlier in table 6. Juxtaposed, these tables indicate the problems inherent in forecasting fuel choices beyond 1985, and the apparent narrowing of the competitive choice between nuclear and fossil fuel plants.

Available information regarding orders for nuclear reactors during 1973-76 suggests that we currently have something close to a nuclear moratorium, if that phrase is taken to mean no new orders for nuclear powerplants are being placed. The potentially large impact of problems associated with the development of nuclear generating capacity has encouraged study of the implications of various possible types of nuclear moratoria. One such study examined the implications of a 6-year ban on new building applications. 59/

Were such a ban to be instituted, nuclear generating capacity was estimated to be some 200 thousand MW less by 1990. 60/ However, total generating capacity would also be some 100 thousand MW less, presumably because the cost of electricity was higher without the low cost nuclear option. 61/ This in turn would mean a reduced demand for electricity. 62/ This particular study did not calculate the impact of this limited moratorium on coal usage.

Consider now another kind of nuclear moratorium. In this case, all capacity in existence and scheduled to be operative by 1985 is shut down. What would this mean for utility coal consumption?

NERC estimated that by 1985 utilities would annually burn 827 million tons of coal. 63/ If currently scheduled and operating nuclear capacity were shut down and the slack taken up by existing and scheduled coal-fired capacity, this would increase utility coal consumption in 1985 to over 1.5 billion tons assuming that much could be produced. This would mean consumption would be more than three times as high as 1976 levels (see table 1).

In summary, the near-term potential for substitution of coal for other fuels in the electrical sector is substantial. In a longer timeframe, the potential for substitution is limited only by the rate at which new, environmentally acceptable capacity is installed.

SUBSTITUTION OF COAL IN OTHER SECTORS

The electrical sector enjoys the widest range of fuel choice. Furthermore, electricity is probably the most convenient and flexible form of fuel use. Given coal's role as an energy source for electricity, can we foresee an increased reliance on electricity generally in the economy as a whole and thus, indirectly, an increased reliance on coal as an energy input?

Various factors determine the choice of electricity as compared to other energy inputs in the economy. Yet the important point is that a number of prominent studies have concluded that the future potential for electricity use is very substantial. ^{64/} Table 9 shows a projection of consumption, by consuming sector, for the years 1985 and 2000. ^{65/}

Indirect Substitution of Coal Through
Increased Reliance on Electricity

As shown in table 9, the household/commercial sector currently derives some 40 percent of its energy from electricity. This is expected by EEI to rise to as much as 60 percent by 1985 and 75 percent by 2000.

Table 9

Consumption of Electricity as Percent of Total Energy
Consumption, 1972 and Potential 1985-2000

<u>Consuming sector</u>	<u>1972</u>	<u>1985</u>	<u>2000</u>
Residential	40	60	75
Commercial	42	55	77
Industrial	27	41	62
Transportation	0	5	29

In 1975, some 50 percent of the newly constructed single family homes and 60 percent of the multi family homes had electric heat. Electricity's share is expected to rise, so long as residential gas hookups remain scarce and retail gas prices continue to increase faster than electricity prices.* While coal furnaces and stoves in residences are a thing of the past, we can probably assume that almost one-half of increased energy use in the household/commercial sector to 1985 will be from coal-generated electricity because of

*During 1935-75, retail gas rates increased nearly twice as much as retail electric rates. The increase for fuel oil was four times as great as for electric rates. ^{66/}

- the higher relative costs of fuel oil for heating;
- the growing unavailability of natural gas; and,
- the absence of prospective technological changes which would reduce electricity's share of new household/commercial uses.*

Many industries involving light or even heavy manufacturing are similar to the household and commercial sectors in terms of factors determining energy use patterns. Principal reliance is on gas, oil, and electricity. For reasons noted above, the choice is likely to favor heavily electricity in the future.

Overall, past trends indicate an increasingly heavy reliance on electric energy. Manufacturing use of purchased electricity increased from 187 billion kwh in 1954 to 518 billion kwh in 1971, a compound annual growth rate of 6.2 percent. 67/ In contrast, total energy use in manufacturing during the same period rose from 2,220 billion kwh (equivalent) to 3,850 billion kwh (equivalent), an annual growth rate of 3.3 percent. 68/ Direct use of coal declined from 91 million tons in 1954 to 61 million tons in 1971, a rate of decline of 2.4 percent per year. 69/

A continued increase in reliance on electric power as a proportion of total energy demand depends on relative price movements. Though difficult to predict, it appears that electricity costs will continue to rise less rapidly than those of other energy sources--particularly in relation to natural gas.** Among all energy sources, electricity demand is most sensitive to shifts in relative prices. FEA estimates such sensitivity to be greater by 50 percent or more compared to natural gas and petroleum products. 70/

*Increasing use of heat pumps would reduce demand for total kwh hours per household, but would likely also increase the share of electricity in the market for heating of new structures.

**While all energy costs are expected to increase, it is the trend of relative prices which is important for many decisions.

On this basis it would appear likely that increased reliance on electricity will evolve over the next decade. A continuation of trends evident in the manufacturing sector during 1954-71 is likely to result in electricity increasing to the level shown in table 9.

The transportation sector is the least amenable to increased reliance on electricity as a main energy source. In the transportation sector, at present, some 96 percent of energy use is derived from oil. Since the coal-fired locomotive is unlikely to return, the prospects for substitution here may depend on

- the outlook for the electric car;
- the outlook for electric rail transport; and,
- the growth of electrified, intra-city mass transit relative to use of cars and busses.

A massive shift toward use of electricity would require major changes in the composition of our transportation capital stock. Since such changes take time, not until the year 2000 does the most optimistic projection of electricity use in transportation indicate significant penetration (table 9). Such penetration apparently requires radical changes in electric car technology and transportation use patterns. 71/ It would probably also require a major diversion of funds from the Highway Trust Fund for mass transit. 72/

Substitution of coal through direct burning

Recent FEA surveys, together with data from other sources, indicate a dramatic long-term decline in the direct burning of coal. In recent years some 20-25 percent of coal-fired boilers in industry were converted to oil or gas to comply with clean air standards. 73/ Theoretically, these converted boilers could be reconverted back to coal. 74/ Such reconversions may be too costly because the existing stock of coal-fired boilers in industry is old and getting older. 75/ Also, in some instances, coal unloading and handling facilities have been dismantled.

The prospects for greater coal use through orders for new boilers seem brighter. In 1973, only six percent of the total capacity of new industrial boilers were coal-fired. 76/ Even this low figure represented an increase over 1967-72. 77/ Furthermore, preliminary evidence indicates that as much as one-third of the steam generating boiler capacity ordered

by industry in 1976 was coal-fired. 78/ Yet these data also imply that considerably more than half of industrial boiler orders are for oil or gas-fired units 79/, despite gas curtailments and the rising prices of oil and gas suggested by table 3.

Coal-fired boilers are ordered less frequently mainly because they cost two to four times as much as gas- or oil-fired units. 80/ Unfortunately, reliable data on the total relative costs--capital, operating and maintenance, and fuel--of differing industrial boilers are presently being developed. 81/ Also, unlike the situation in the utility sector, industrial firms do not announce their expansion plans in a systematic manner several years into the future. 82/ Other reasons for current industrial preference for oil- or gas-fired boilers include the desire to comply with environmental standards, convenience, and the unavailability of coal hauling and handling equipment.

In view of these disadvantages of using coal to generate steam, the prospective industrial demand for coal for direct burning is uncertain. On the one hand, recent trends regarding orders for new boilers suggest a resurgence of coal as an industrial boiler fuel. On the other hand, the new coal-fired boilers may principally replace older coal equipment so that net increases in coal-fired capacity might be modest.

While the impact on total coal use due to greater direct burning in industry may be too small, the potential in terms of relative use of natural gas by certain key industries is greater. In particular, four industries (cement, chemicals, paper, and steel) presently account for 83/

- two-thirds of manufacturing coal consumption,
- one-half of manufacturing oil consumption, and
- one-third of manufacturing gas (and electricity) consumption.

One recent study has concluded that these four industries could, in the aggregate, by 1985, substitute enough coal to conserve annually some 10 to 15 million barrels of oil and some 325 to 400 billion cubic feet of gas. For these industries, these savings would represent up to 17 percent of 1971 gas consumption. 84/ In terms of individual industries, the largest substitution occurs in cement and the smallest in steel. 85/

The results of this study are based on substantial increases in both coal and gas prices, with somewhat smaller increases in oil prices. ^{86/} The possibility of greatly increased natural gas curtailments was, however, not considered. Therefore, the substitution of coal in the amount of 17 percent of 1971 gas consumption may understate likely future reductions in industrial gas usage.

Of course, this gas is most likely to be replaced by electricity, not coal, as noted previously. Nevertheless, these results suggest that coal as a direct burning option can make a significant contribution to reduced usage of gas as an industrial boiler fuel in selected industries. At the same time, coal will indirectly provide industrial energy through coal-fired electricity.

Ten years ago industry generated 17 percent of its own electricity requirements. ^{87/} The current percentage is somewhat less. ^{88/} It is interesting to consider whether this share might rise in the future.

Industrial generation of electricity has declined over time in the United States because electric rates for large industrial users have declined. In large part, these industrial electric rates have declined because electric utilities have benefited from increasing economies of scale. However, in recent years, such economies have been less attainable and the recent increases in fuel prices have made the fuel component of electrical generation costs more significant.

In that regard, it is important to note that while the thermal efficiency of industrial electrical generation by on-site powerplants is greater than central station generation ^{89/}, the overall efficiency of central station generation has historically been greater mainly because large powerplants benefit from substantial economies of scale. Since 1970, opportunities for further increases in cost savings through economies of scale have diminished and fuel costs have increased noticeably. If rising fuel costs are not compensated by technological advances in the utility sector, the resulting higher prices of electricity may stem (or even reverse) the decline in industrial generation of electricity.

Whenever industrial steam is generated, there is a potential opportunity for generating electricity although this is taken advantage of in only a minority of cases. Using steam produced by industrial boilers for the dual purpose of electric generation and other industrial needs

is a major example of cogeneration. Under the cogeneration concept, additional energy is added to raise the quality of the steam to that required to drive a generating turbine and produce electricity. The waste steam from the turbine is then used for other industrial processes. Not all industrial boilers produce a large enough steam load to make cogeneration economically attractive. However, the unexploited potential seems substantial. In fact, one recent study has concluded that by 1985 the equivalent of 680 thousand bpd of oil could be saved through greater reliance on industrial cogeneration of electricity. 90/ However, a variety of impediments must be overcome if fuel savings of this magnitude are to be obtained.

Utilities have had long standing policies that discourage industrial generation of electricity. Rate schedules have been designed to favor large industrial users. The rise of utilities as a standby source for backing up industrial power generation has been discouraged through high demand charges which are levied even if no electricity is consumed. 91/ In addition, utilities are reluctant to buy the excess power produced by industry because it is often erratically produced. 92/ The extent to which the cogeneration plant will become a regulated enterprise is also a crucial factor. State regulation on sales of any excess power to individuals or public utilities is a consideration. And if any of the power generated is sold across State lines, the facility will probably become subject to Federal regulations under the Federal Power Act. 93/

While the potential for increased cogeneration of electricity by the industrial sector seems substantial, the effect that such an increase, if it should occur, would have on the direct burning of coal by the industrial sector seems limited. A large percentage of industrial steam is produced with oil- or gas-fired boilers. As pointed out earlier, conversion to coal will be made reluctantly because the cost of a coal-fired plant may be two to four times that of a gas or oil-fired plant and the former creates material handling, storage, and environmental problems.

Some of the disadvantages of burning coal can be overcome using a variant to the cogeneration technique described above. This technique involves a large central powerplant located within a cluster of industrial or residential users. The powerplant sells both electricity and processed steam to consumers within the complex. In this way, the powerplant has a purchaser for a large quantity of what might otherwise be waste heat.

Cogeneration facilities located within major industrial clusters offer advantages in burning coal because of economies in coal purchasing and handling, powerplant size, and in financing of such ventures. Also, environmental problems can be better dealt with at large cogeneration plants. 94/ This type of cogeneration could increase the amount of electricity produced through the direct burning of coal. However, it would seem that only a limited number of industrial sites could meet the criteria. Thus, the likely effect on the amount of coal burned by the industrial sector.

In summary, the immediate prospects for substitution of coal as direct burning in the industrial sector are limited. Indeed, the administration projects a four percent compound annual growth rate in coal usage by industry versus a nine percent growth rate for oil consumption unless the National Energy Plan is implemented. 95/ Such implementation is predicted to greatly increase coal usage by industry. However, GAO has considerable doubt that implementation of the National Energy Plan will have the full impact expected.

Substitution of coal through synthetic fuel development

Gas manufactured from coal was once relatively important. 96/ For years some observers have been anticipating a comeback as natural gas reserves diminish. In 1972, the Bureau of Mines (BOM) predicted the following scenario for synthetic gas from coal (versus 20,400 trillion Btus currently derived from natural gas in 1975). 97/

<u>Year</u>	<u>Trillion Btus of gas from coal</u>
1980	430
1985	2,000
2000	7,140

That same study also forecasted 2,140 trillion Btus of synthetic liquids from coal. 98/

In its 1975 forecast, BOM revised these estimates substantially downward. 99/ However, given that the Congress has chosen not to accelerate development of the synthetic sector at this time, the downward revisions are probably still too high.

What are the prospects for synthetic fuels in the absence of major financial assistance by the Government? The answer obviously depends on relative costs. The most recent forecast of such costs by ERDA is presented in table 10 below.

Table 10

ERDA Best Estimate of
Wholesale Prices for Major Fossil Fuels and
Synthetic Fuels Derived from Coal (note a)

Fuel	<u>Wholesale Prices (note b)</u>	
	<u>1985</u> <u>(1975 cost per million Btu)</u>	<u>2000</u>
Oil	\$2.24	\$2.87
Gas	1.93	2.19
Coal (note c)	0.61	0.69
Synthetic crude	d/3.45	d/3.57
High-Btu gas	d/3.54	d/3.65

a/These estimates were prepared by ERDA and presented in the unpublished draft of the 1977 National Energy Outlook. ERDA has reviewed these estimates and has not objected to their inclusion in this report.

b/These wholesale prices are not immediately comparable to the prices in table 3. However, approximate delivered prices to utilities for the year 2000 are projected at:

residual oil	\$3.15 per million/Btus
gas	2.41 per million/Btus
coal	1.14 per million/Btus

Comparing these data to those in table 3 leads to the inference that coal's price advantage over oil may be wider in 2000 than in 1975.

c/Assumes approximately 60 percent surface and 40 percent underground mining.

d/Tennessee Valley Authority officials, in commenting on the report, believe that 1985 prices for synthetic fuels are too low. They believe synthetic crude prices would be nearer \$5.90 and the high-Btu gas should be above \$4.00 per million Btus.

The unmistakable message of table 10 is that synthetic fuels from coal are unlikely to be cost effective in this century. Consequently, synthetic fuels would only become a major factor if gas and oil were unavailable at projected price levels. Such a circumstance could occur if, in the face of declining domestic production, limits are set on imports and price controls based on cost and are continued indefinitely. Even under such circumstances, however, it is as likely that coal would be used to generate electricity as to manufacture synthetic fuels.

For certain purposes, however, such as household and commercial heating, high-Btu gas compared to electricity may have a more promising future than implied by table 10. Another alternative, which GAO hopes to consider further, involves transport of coal to consuming centers, conversion to low- or medium-Btu gas, and used as gas for industrial, commercial, residential heating, etc., to replace natural gas.

Recapitulation of overall fuel substitution

The potential for substitution of coal is greatest in the electrical sector. By 1985, roughly half of the energy input to this sector will likely be derived from coal. Considerable uncertainty surrounds the prospects for coal after 1985. Whether coal's share in this sector rises noticeably above 50 percent in this century or beyond depends crucially on relative shifts in the risks and economics of electric power sources. A well developed nuclear option will reduce the projected increase for coal. On the other hand, there are indications that the opposite could occur.

Beyond the issue of how much coal is used for power generation is one which asks how much power generation is needed in the context of any aggregate energy use pattern. Indications are that significant past trends of increasing relative reliance on electricity will persist in the future. As a result, if coal merely holds its own in the fuel mix for power generation, demand is likely to rise, as energy users shift from gas and oil to electricity.

Given the limited potential for direct burning of coal and the economic and technological uncertainties of coal synthetics, the principal prospects for coal seem inextricably tied to the prospects for electricity for the remainder of this century.

The extent of substitution is principally a function of time. In the electrical sector, high degrees of coordination among utilities permit some substitution of coal for other fuels within days or weeks. Within several months or a year, some conversion of powerplants is possible, and differing plants can be utilized at varying capacity rates. In the course of several years, some new plants can be added and others scrapped. Full substitutability must also consider the time it takes to build a nuclear powerplant--about 10 years. Given time, substitution rates also depend on growth rates for electricity and the depreciation rates for electric powerplants.

The future of coal and of electricity depends on relative price movements among alternate energy sources. Though coal at present offers a price advantage in terms of costs per Btu as compared to other energy sources, this advantage is greatly diminished and often eliminated when costs of use are considered. These costs are mostly related to the adverse environmental consequences of coal combustion. Current economics indicates that the competition among electrical utility fuels is now most keen between coal and nuclear.

IMPLICATIONS OF COAL USE FOR WIDELY DIFFERENT ENERGY NEEDS AND USE PATTERNS

Differing levels of aggregate energy demand and electricity usage could affect the demand for coal in various ways. For example, rapid increases in energy demand could lead to higher energy prices, thereby making synthetic fuels from coal cost effective. Or the increased relative importance for the electrical sector could enhance the role of coal in supplying energy needs.

The future of aggregate national energy needs is uncertain. In the past, even without the turbulence generated by OPEC, forecasters were not able to clearly perceive the future. Developments in recent years make projections even more suspect.

Factors which make energy forecasting difficult are readily identifiable. At least three are of great importance--population and economic growth trends; composition of national output; and cost of energy relative to that of other resources. To develop an estimate of energy needs for a year, for example, 1985 or 2000, one must, at least implicitly, presume future trends to some extent regarding each of these factors. In addition, one must specify what implications these trends have for overall energy consumption.

The relationship among energy use, relative energy costs, and the rate of economic growth has been highly variable. The ratio of gross energy use to gross national product (GNP) rose from 1909 to 1919, declined from 1923 to 1944, and has remained relatively constant since then. 100/ The energy/GNP ratio in 1975 was 71 percent of its 1923 value and approximately equal to its lowest value since 1969. 101/ The future value of this ratio continues to be a source of much speculation.

There is a brief discussion of these relationships in chapter 2 of the National Energy Plan, and the administration's overall goal of achieving a 46 percent increase in GNP by 1985 while reducing the annual growth of energy demand to below 26 percent.

The relationship between relative energy cost and use is even less known. Most agree that higher relative energy costs will reduce energy use but the question of just how much and over what period has resulted in various answers. These and other factors account for differences in the total energy growth and the fuel mix of the two scenarios examined in the following pages: the BOM energy forecast through the year 2000 and the EEI low growth scenario.

These two were chosen because they were, at the time this study was begun, representative of possible ranges of energy demand. Furthermore, BOM has an important historical role in research related to coal, while EEI presumably reflects current thinking in the electric utility industry.* President Carter's National Energy Plan was not available when this study was started, so we were not able to use it as one of our scenarios for analytical purposes. However, we have been able to compare the coal supply and use goals of the National Energy Plan with the BOM and EEI scenarios. These comparisons are noted in the following discussion. See also, GAO's report "An Evaluation of the National Energy Plan" (EMD-77-48, July 25, 1977).

*It should be noted that EEI presented several scenarios. GAO chose to utilize the EEI "low growth" or low energy demand scenario as a "counterweight" or reference point with which to compare the BOM forecast, which projected high energy demand.

A summary of energy needs and electrical generation under the BOM and EEI scenarios is presented below. 102/

Table 11

Summary of Energy Needs and Electric Use
Under Alternative Scenarios, 1985 and 2000

<u>Scenario</u>	<u>Gross Energy Demand</u>		<u>Electrical Generation</u>	
	<u>1985</u> (Quadrillion Btus)	<u>2000</u>	<u>1985</u> (Trillion kwh)	<u>2000</u>
BOM	103.5	163.4	3.96	8.65
EEI	101.2	109.5	3.17	5.17
Actual 1975 consumption	71.1		1.88	

As table 11 indicates, the two estimates for 1985 are fairly similar. However, they diverge markedly by the year 2000. To understand the construction of these scenarios, an effort was made to determine and compare the nature of underlying assumptions. For the period through 1985, insofar as assumptions were made explicit in building these estimates, they are similar with regard to expected national growth patterns and the relation between energy use and economic activity. 103/ Two principal factors explain differences subsequent to 1985. EEI assumes a slower growth rate and higher energy prices than does BOM. The slower growth explains about 16 quadrillion Btus of the difference, while relative price differences appear to explain most of the balance. It should also be noted that both scenarios imply a greater aggregate energy demand for 1985 than President Carter's national energy goal.

For the purposes of discussion here, the BOM and EEI scenarios have special interest because of their potential implications for coal demand. Both project substantial expansion in national reliance on electric power. Table 12 shows that the projected growth rates for the electrical sector far exceed those for all combined sectors. Indeed, under the EEI scenario the electrical sector grows nearly five times as fast as all combined sectors: 2.82 percent per year for the electrical sector versus 0.53 percent for all combined sectors. These higher growth rates for the electrical sector naturally imply increasing electrification and use of coal, both in relative agreement with President Carter's proposals in his National Energy Plan. By the year 2000, therefore, the share of the electrical

sector rises to nearly one-half under both scenarios, as depicted in the bottom part of table 12.*

Table 12

Growth of Electrical Sector Versus Total

		Growth rates			
		1975	1985	1985	2000
		BOM	EEI	BOM	EEI
		----- (Percent) -----			
	1975 (Quadrillion) Btus				
Total energy (gross input)	71.1	3.83	3.59	3.09	0.53
Electrical (gross input)	20.1	6.89	5.28	4.77	2.82

Proportion of Electrical Input to Total Energy

<u>1975</u> <u>Actual</u>	<u>1985</u>		<u>2000</u>	
	<u>BOM</u>	<u>EEI</u>	<u>BOM</u>	<u>EEI</u>
----- (percent) -----				
28	38	33	48	47

The two scenarios anticipate that nearly half of our energy will be converted into another form rather than be used directly. Such a trend favors coal and uranium over natural gas and oil.

The EEI scenario is of special interest since between 1985 and 2000 total energy use is expected to decline in nearly every major consuming sector except electrical where an increase of more than 50 percent is assumed. In the EEI scenario, electricity consumption rises from 1.88 trillion kwh in 1975 to 3.17 trillion in 1985 principally because electric rates are projected to decline in 1975 dollars from 2.07 cents per kwh to 1.97 cents per kwh, during 1975-85. This decline in electricity prices is based on the expectation in the EEI scenario that technological change will offset the effects of rising fuel prices on the costs of electrical generation. 104/

*The data in tables 12 and 13 are derived from more detailed data presented in app. II.

During 1985-2000, the EEI scenario expects real prices for electricity to remain roughly constant. Accordingly, the growth in electrical generation declines to 2.8 percent per year during this period, versus 5.2 percent per year during 1975-85.

The BOM forecast contains no explicit assumptions about energy prices. 105/ However, the BOM forecast appears consistent with an assumption that electricity prices will decline during 1975-2000 at half the past rate of decline in such prices up to 1970. 106/

Despite the fact that each scenario reflects strong expectations regarding growth in electricity use, similar expectations are not projected for coal use. This is shown in table 13 which compares annual growth rates for coal and total energy, and coal's importance in the total energy picture under the two scenarios.

Table 13
Growth of Coal Versus Total Energy

	Annual growth rate (percent)							
	1975-85				1985-2000			
	BOM	BOM without synthetics	EEI	EEI without synthetics	BOM	BOM without synthetics	EEI	EEI without synthetics
Total energy	3.83	-	3.59	-	3.09	-	0.53	-
Coal	4.98	4.73	2.21	1.50	3.33	1.65	1.20	(-0.31)

Coal Input as a Percent of Total Energy Input

<u>1975</u> <u>Actual</u>	1985				2000			
	BOM	BOM without synthetics	EEI	EEI without synthetics	BOM	BOM without synthetics	EEI	EEI without synthetics
18.8	20.6	20.1	16.1	15.0	21.3	16.3	17.8	14.0

The most important information in table 13 is contained in the upper right hand side. These figures show that during 1985-2000, both scenarios predict faster growth for total energy than for coal outside the synthetic fuels sector. In fact, the EEI low demand scenario projects an absolute decline in coal usage unless a synthetic fuels sector can develop.

Table 13 also reveals that, under the comparatively "optimistic" BOM scenario, the share of coal in the total energy picture will rise to only 21 percent by 2000. As shown in table 1, this was coal's approximate share in the 1960s.

In summary, the most optimistic growth rate in demand for coal is assumed by BOM for the period to 1985 and equals 4.98 percent, as compared to an expected overall growth rate of 3.83 percent. In the context of this high growth scenario, there will not be a significant demand for coal in the future. The EEI scenario expects even less demand for coal. Coal growth through 1985 is expected to be about half that of overall energy needs. Beyond 1985 coal use will generally decline except as a synthetic. Even in the electrical sector, in which a 50 percent expansion is projected, coal use is expected to decline.

The key assumption in the two scenarios, which greatly affects electric utility demand for coal, is an increasingly heavy reliance upon nuclear power generation. While in 1975 non-fossil fuel generation accounted for 4.8 quadrillion Btus of total consumption, by 1985 the expected contribution is set at between 14 and 16 quadrillion Btus, and for 2000, between 32 and 52 quadrillion Btus. 107/

As already noted, considerable uncertainty surrounds fuel mix decisions in the 1980s and even more in the future years. A review of the two scenarios indicates that the future of coal relates principally to its ability to compete on an interfuel basis, regardless of levels of aggregate energy demand. If the future contains an efficient and comparatively economical and environmentally acceptable nuclear option, coal may not even hold its present position in the Nation's fuel mix.

But what if the nuclear option does not materialize, or what if it is possible to significantly lower the relative cost of coal use? What implications would this have for aggregate coal demand, particularly if the Nation chooses to increase its overall reliance on electric power? Neither of the scenarios considered here are of any help in answering questions such as these.

We attempted to answer these questions through use of the FEA's National Coal Model (NCM). In effect, the NCM was asked to determine the level of coal consumption under the two scenarios with the supply assumptions incorporated in the model. These supply assumptions related to levels and types of electrical generating equipment, prospective markets for synthetic fuels, etc.

Unfortunately, definitive and reliable answers could not be obtained in time for inclusion in this report. The NCM is new and further adjustments seem necessary before its projections can be accepted with a high degree of confidence. However, the projections and other data obtained from our use of the NCM were approximately consistent with comparable projections from other sources. Therefore, we can summarize the principle findings obtained from our use of the NCM.

The most important result of the NCM output made available to GAO was that the potential consumption of coal in the electrical sector was far greater than envisioned by either the BOM or EEI scenario. The principal reason for this difference was the relative optimism, of both the BOM and EEI scenarios, about the future development of nuclear power. The NCM projects a considerably smaller relative role for nuclear power in the electrical sector. This result also implies that the key to coal development is the cost and convenience of using coal compared to competing alternatives. The level of demand for electricity is, at least potentially, less important.

The NCM also enabled us to analyze geographic patterns of coal development. Consumption of coal by utilities by 1985 was projected to grow nearly twice as fast in the West as in the East* while the Central** area consumption was projected to grow at only one-third the rate of the West. These differences were not affected much by the level of electrical generation for the Nation. Of course, electricity demand can be expected to grow faster in the West. Yet some of this difference is due to prospective gas curtailments and the relatively low cost and convenience of burning coal in certain western areas.

*The East consists of Census Regions 1-3 and West is Regions 6-9.

**Census Regions 4-5.

The geographic pattern of utility coal consumption is approximately matched on the production side. For example, the growth rate of production during 1975-85 was projected by the NCM to be more than five times as great in the Northern Great Plains as in Appalachia or the Midwest. This difference reflects the low-sulfur content of coal from the Northern Great Plains and its comparatively lower mining costs. These advantages would apparently enable coal from States west of the Mississippi to successfully capture markets previously served by Midwestern and Appalachian producers. Furthermore, coal prices have increased more than coal transport rates so that the relative importance of transport costs in the price of coal has declined. This contributes to the current advantages of western coal. Once again, these regional differences were generally unaffected by the overall level of electrical generation. So, regional differences in coal development appear to depend more on decisions regarding severance taxes, air quality standards, etc. than on the level of electricity demand. Conceivably, the most important factor affecting regional coal development patterns will be the methods chosen for meeting clean air standards, a subject discussed in chapter 6.

In summary, many possible demand levels for coal can be projected, even in the context of the next decade. How coal fares in competition with other electric power generation alternatives is of vital importance. Even an economy which relies primarily on electrical energy will not automatically turn to heavier use of coal in relative terms since currently it is not viewed by all as a superior alternative to nuclear energy.

The probability of rapid coal development is apparently enhanced more by the relative cost advantage for coal than by the rapid growth in energy usage. If rapid growth in coal usage is attained, above average growth could occur in coal production--and consumption--in the West. The extent of a shift to the East, if any, as a result of requiring scrubbers on all plants has not been determined.

In our earlier report to the Congress, An Evaluation of the National Energy Plan, we assessed the various recommendations of the administration to increase coal use and concluded that a lot more needs to be done. 108/ We also noted that the work we have been doing on the production and use of coal raises serious doubts about the possibility of achieving the administration's plan of producing and using 1.2 billion tons of coal by 1985. Given all the physical, economic, environmental, and public health considerations,

it appears to us that producing and using even a billion tons by 1985 would be difficult. Assuming, however, that the difference between the administration's plan and reality is a matter of 200 million tons, we calculated that this would be a shortfall on the domestic energy supply side equivalent to an annual use of 2.3 million barrels of imported oil per day, as presented in the fuel balance tables in the National Energy Plan. GAO's calculation was based on the administration's estimates of what a shortfall of 200 million tons of coal would entail using the administration's conversion factors. However, the administration used an average Btu rate conversion factor which does not reflect the true value of the oil equivalent of coal.

Using appropriate conversion factors for each use where coal would substitute for oil, GAO estimates that the 2.3 million barrels of oil shortfall noted above would actually be 2.2 million barrels of oil equivalent per day.

Upon further review, we have discovered an additional problem. As noted above, the administration calculated supply and demand on the basis of quadrillion Btus and then converted these to millions of barrels of oil a day equivalent. Using the same conversion factor analysis as above, GAO estimates that the oil equivalency of the remaining one billion tons of coal could be 1.1 million barrels per day less than the administration's figures shown in the fuel balance tables in the National Energy Plan. Thus the number of barrels of oil equivalent per day shown in the fuel balance tables for one billion tons of coal (without the energy plan) should be 11.1 million barrels per day instead of the 12.2 million barrels shown.*

The following table compares the two approaches and shows the difference in the results as far as coal is concerned.

*These figures should be adjusted downward by 1.4 million barrels per day equivalency for metallurgical coal which has no oil substitutability.

Table 14

Comparison of GAO and Administration Estimates
of Converting Coal into Equivalent Barrels of Oil

<u>Sector</u>	<u>Coal Energy P.I.E.S. Model (Note a/)</u>	<u>GAO</u>		<u>Administration</u>	<u>Difference</u>
		<u>Coal Energy (Note b/)</u>	<u>Oil Equivalent (Note b/)</u>	<u>Oil Equivalent (Note c/)</u>	
	----- (Trillion Btus) -----			----- (Million barrels) -----	
Industrial (Note d/)	2,537.3	943.9 <u>1,593.4</u> 2,537.3	.4 <u>.7</u> 1.1	1.3	0.2
Utilities	16,449.4	6,349.5 <u>10,099.9</u> 16,449.4	2.9 <u>4.4</u> 7.3	8.2	<u>0.9</u> <u>1.1</u>

a/Trillion Btus for sector as calculated in the Project Independence Evaluation System (P.I.E.S.) Model (base case), used by the Administration to calculate energy supply and demand for 1985.

b/Assumes Btu conversions for most likely substitutions, based on 1975 experience:
5,825,000 Btus/barrel for distillate; and
6,287,000 Btus/barrel for residual oil.

c/Computed across the board using an average oil Btu value of 5,479,000 Btus per barrel.

d/Includes synthetics. Excludes metallurgical coal.

As the table indicates, the GAO and administration estimates of trillion Btus are identical, but there is a difference of 1.1 million barrels of oil a day equivalent between the two estimates because of the different conversion factors used. Under the administration's average conversion factor, the production of one billion tons of coal would equal 9.5 million barrels of oil equivalent while under a historical conversion rate, it would equal only 8.4 million barrels of oil equivalent. If this difference in conversion factors implied a real world shortfall, it would have to be made up in one of three ways: additional imports; increased domestic production from other sources; or increased conservation efforts. If, on the other hand, the oil equivalent numbers in the National Energy Plan simply reflect a mechanical use of an average conversion factor from detailed estimates based on actual quantities, there would be no shortfall since both supply and demand would be less in barrels of oil equivalent. As discussed in the next paragraph, we are continuing our investigation into this possibility.

In any case, these considerations raise questions about the factor used by the administration in converting to barrels of oil equivalent per day for other domestic energy sources, which in turn raises questions about the administration's total estimates regarding energy supply and demand. GAO believes the administration should either have presented its analysis on the basis of Btus or used a more detailed set of conversions to oil equivalency which recognized historical and other trend data in developing the conversion factor. Otherwise, GAO believes that the net effect could be to increase the total energy supply and demand estimates when stated in barrels of oil equivalent. While not part of this study, we are continuing this analysis and will be reporting our findings to the Congress.

SUMMARY

Coal usage declined markedly during the past 25 years relative to natural gas and oil. Even in absolute terms, total coal consumption grew at an average annual rate of only 0.49 percent during 1950-75. Coal is not as convenient to use as gas and oil because it is more difficult to handle and to ship, and, most importantly, it causes more pollution when burned. Even now, for example, nearly 50 percent of all coal consumption for powerplant use is out of compliance with existing air quality standards.

Our main observation in this chapter is that coal use will increase significantly in absolute terms, but may not increase much as a percentage of the Nation's total energy consumption.

Given the Nation's growing reliance upon oil imports, the conversion from oil to coal and nuclear is an important alternative to consider. To promote conversion, Congress passed the Energy Supply and Environmental Coordination Act. 109/ As of December 1976, 74 conversion orders had been issued by the Federal Energy Administration. However, only 11 have received approval by the Environmental Protection Agency, and only three powerplants with 158 MW of capacity have been converted. Fifty-one orders have been stayed pending the installation of improved pollution control equipment.

The direct conversion possibilities in the transportation sector between the present and the year 2000 are not very great; in the residential and commercial sector they are also very small; and in the industrial sector they are limited. It is in the utility sector that the direct conversion possibilities look most promising.

An attractive means of inducing the substitution of coal (and nuclear) for oil or gas in the utility sector involves improved load management through such measures as peak load pricing and central dispatching (for better coordination). Broadly defined, improved load management could increase coal utilization by utilities by 149 million tons.

With full conversion of oil- and gas-fired utility powerplants to coal, optimal load management, and maximum thermal efficiency, electric utility consumption of coal could rise to some 873 million tons in 1985. Of course, this level of coal usage by utilities is highly unlikely by 1985. One reason is that the growth in electricity demand will most likely not be sufficient to warrant such large coal purchases. Furthermore, the ability of the utilities to burn coal in compliance with air quality standards at an acceptable cost to the consumer has yet to be demonstrated. The key point seems to be that improved load management, particularly through rate reform, offers considerable promise for promoting greater coal utilization.

Future relative demand for coal depends almost entirely upon the outcome of the contest between nuclear and coal-fired electricity generating plants. If the future contains an efficient and comparatively economic and environmentally acceptable nuclear option, coal may not hold its present relative position in the Nation's total energy consumption picture.

Nuclear's future looks more uncertain than it once did. For example nuclear units accounted for over one-half of the uncompleted capacity in MW in the April 1 to September 30, 1976 period. Of the total 21,272 MW scheduled to be placed

in service, only 12,505 MW were actually put on line. In contrast over 80 percent of the coal-fired units scheduled for commercial operation during the period were actually entered into service.

Despite these recent indications that nuclear is unlikely to live up to earlier expectations, current utility plans are still predicated on expansion of nuclear power relative to expansion of coal-fired generation. Nuclear's apparent advantage is three mills over coal plants without scrubbers and nearly four mills for coal plants with scrubbers--a cost advantage of 15 to 20 percent. Nuclear generation is substantially more capital intensive than is coal-fired generation even with scrubbers. The assumed advantage of nuclear has been in projected fuel costs of one-third to one-half that of coal-fired facilities. Lately, however, increasing doubts have been voiced regarding the superiority of the nuclear option. These doubts concern costs of radioactive waste disposal and decommissioning, and the risks of fuel reprocessing and the fast breeder reactor.

GAO interviews with utility officials indicated that they believe that only large changes in projected costs would significantly alter the current choice in favor of nuclear generation. Recent developments seem to suggest, however, that wide shifts in the comparative costs of nuclear versus coal may not be so improbable. For example, the utility officials noted that nuclear fuel costs would have to more than double or coal prices would have to fall by one-half or more to shift the balance in favor of coal. Given recent trends in uranium prices, a doubling of nuclear fuel costs is certainly not impossible.

Though the outcome is still uncertain, clearly the contest between nuclear and coal-fired plants is getting closer.

Synthetic fuels from coal are unlikely to be cost effective in this century. Such fuels would only become a factor if gas and oil were unavailable at projected price levels.

A regional analysis of future coal development suggests that the coal industry could experience greater expansion west of the Mississippi. Appalachia and the Midwest could apparently grow at only one-half the rate for the industry as a whole. A requirement for scrubbers on all coal-fired plants could reduce the advantage of western low-sulfur coal and will have an effect on this analysis. The factors are complex, involving considerations of higher western versus lower eastern transportation distances and costs,

lower western surface mining costs versus higher eastern, and higher eastern Btu content versus lower western.

We have doubts about the possibility of achieving the administration's plan of producing and using 1.2 billion tons of coal by 1985 or, for that matter, even the level of one billion tons the administration assumes will be achieved without its plan. Given all the physical, economic, environmental, and public health considerations, it appears that producing and using even a billion tons by 1985 will be difficult. Assuming, however, that the difference is 200 million tons, the shortfall on the domestic energy supply side in terms of oil equivalent would be 2.3 million barrels per day. In addition, GAO does not agree with the administration's formula for computing the oil equivalents of coal. The magnitude of the difference in the administration's calculations as compared to GAO calculations, as far as coal is concerned, is about 1.1 million barrels of oil equivalent per day.

These considerations raise questions about the factor used by the administration in converting to barrels of oil equivalent per day for other domestic energy sources, which in turn raises questions about the administration's total estimates regarding energy supply and demand.

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CHAPTER 3

HOW MUCH DO WE HAVE?

As of January 1974, there were 3.9 trillion tons of coal resources in the United States, according to the U.S. Geological Survey (USGS). 1/ Of this total resource, 1.7 trillion tons were classified as identified resources and 2.2 trillion were classified as hypothetical or undiscovered resources. 2/ Coal resources in the ground that can be mined economically are termed reserves*, i.e., the quantity that can actually be mined given present technological, economic, and legal constraints. According to the Bureau of Mines, about 256 billion tons of the identified resources are classified as reserves and are equivalent to about 5,040 quadrillion Btus**. 3/ When compared with other domestic fossil fuel reserves (oil, natural gas, oil shale, and tar sands), coal represents about 90 percent of the Nation's fossil fuel reserves. 4/ The high coal demand forecast considered in this report in 2000 shows coal consumption at 1,586 million tons. If the high forecast for 2000 materializes which assumes coal production grows annually at 3.69 percent from the 1976 production level of 665 million tons, the reserves of 256 billion tons, estimated under present economic and technological conditions, could meet U.S. coal demand for about 74 years. However, as coal prices increase, coal resources which were not profitable to mine previously would become profitable. This would extend the life of the U.S. reserves.

Despite the vastness of U.S. coal deposits, there are several problems which may influence the potential recoverability of certain reserves and in turn affect national and regional levels of recoverability. These problems are discussed under the following sections

*As used in this chapter, the term reserves denotes recoverable reserves.

**To illustrate the vastness of the Btu equivalency of estimated coal reserves, 1 quadrillion Btus provide enough energy to electrically heat and cool about 7 million typical American homes for one year, and are equivalent to 180 million barrels of oil or 1 trillion cubic feet of natural gas.

Note: Numbered footnotes to ch. 3 are on pp. 3.24 to 3.29.

- Coal resource and reserve concepts: definition and measurement.
- Reliability and usefulness of reserve and resource estimates.
- Sulfur content of coal resources and reserves.
- Recoverability of reserves.
- Implications of Federal coal ownership.

COAL RESOURCE AND RESERVE CONCEPTS: DEFINITION AND MEASUREMENT

The criteria for measuring and estimating coal deposits embrace two commonly used concepts--resource and reserve. Resources are deposits of coal in such form that extraction is currently and/or potentially feasible; reserves are coal deposits that can be extracted under current economic and technological conditions.

Coal resources

Within the framework of resources, coal deposits are estimated by the USGS and are classified as identified resources and undiscovered resources.* Identified resources refer to deposits of coal whose location, quality (sulfur, ash, moisture, Btu content, etc.) and quantity have been mapped and are known to exist from geologic evidence supported by engineering and measurements of geologic reliability. The concept of undiscovered resources recognizes deposits of coal surmised to exist in unmapped and unexplored areas on the basis of broad geologic knowledge and theory. Both subclassifications of resources include coal deposits in beds of minimum thickness (14 and 30 inches, depending on coal rank)** occurring at depths to 6,000 feet. 5/

*Our discussion on undiscovered resources refers to hypothetical resources.

**Identified resources (anthracite coal excluded) include beds of bituminous coal 14 inches or more thick, and beds of sub-bituminous coal and lignite 30 inches or more thick.

Coal reserves

The term reserves refers to portions of identified coal resources that can be mined under current engineering and economic conditions; estimates are referred to as the demonstrated reserve base and reserves. The demonstrated reserve base relates to coal deposits at depths and seam thicknesses similar to those from which coal is currently being mined--generally having a seam thickness of 28 inches or more for bituminous coal and 60 inches or more for sub-bituminous and lignite coal at depths to 1,000 feet. ^{6/} BOM has estimated the demonstrated reserve base to be 429 billion tons. ^{7/} That portion of the demonstrated reserve base which can actually be mined given present technological, economic, and legal constraints is termed reserves.

Reserves are classified, by mining method, as either surface or underground. Presently, surface reserves can be economically mined at depths generally no greater than 120 to 250 feet ^{8/}; underground mineable reserves, at depths to 1,000 feet. Traditionally, an average of 80 percent of the surface mineable demonstrated reserve base has been recovered while only 50 percent of the underground demonstrated reserve base has been recovered. ^{9/} These recovery rates when applied to the demonstrated reserve base yield "recoverable" reserves of 256 billion tons.

Location of U.S. coal resources and reserves

For purposes of analyzing coal deposits, coal-bearing States have been grouped into three regions: the Eastern, Central, and Western regions. The Eastern region includes all coal-bearing States east of the Mississippi River, except those in the Central region--Illinois, Indiana, and Ohio. The Western region includes all coal-bearing States west of the Mississippi River. Table 1 summarizes estimated resources and reserves for the three regions.

About 82 percent, or 3.2 trillion tons, of total coal resources are located in the Western region. Of the 429 billion tons associated with the demonstrated reserve base, 46 percent is found in the Eastern and Central regions (about 23 percent in each region) and 54 percent in States west of the Mississippi River. Estimates of reserves show 58 percent in Western States with the remainder about evenly split between the Eastern and Central regions.

Table 1U.S. Coal Resources and Reserves (note a)

<u>Region</u>	<u>Coal resources (note b)</u>			<u>Coal reserves</u>	
	<u>Identified</u>	<u>Hypothetical</u>	<u>Total</u>	<u>Demonstrated reserve base (note c)</u>	<u>Reserves (note d)</u>
----- (millions of tons) -----					
Eastern	259,935	93,685	353,620	97,690	53,641
Central	220,035	128,152	348,187	97,364	53,947
Western	<u>1,234,287</u>	<u>1,975,508</u>	<u>3,209,795</u>	<u>234,287</u>	<u>148,107</u>
Total	<u>1,714,257</u>	<u>2,197,345</u>	<u>3,911,602</u>	<u>429,341</u>	<u>255,695</u>

a/Resource and reserve estimates exclude anthracite coal deposits.

b/Resource estimates as of January 1, 1974 (U.S. Geological Survey).

c/March 1975 estimates (Bureau of Mines).

d/GAO computation.

Quality dimensions of resources and reserves

Coal is commonly classified as to particular chemical and physical properties which relate to the quality of coal for usage purposes (direct combustion in boilers or for conversion into synthetic fuels). The qualities in coal which are recognized as important are its heat content (Btu per pound), sulfur, trace element, moisture, and ash contents. ^{10/} Coal deposits of the Eastern and Central regions have a higher heat content than most of those found in Western States.

Coal deposits in the Eastern and Central regions are predominantly bituminous in rank, having a heat content range of 10,500-14,000 Btus per pound. Western coal, on the other hand, consists of bituminous, subbituminous, and lignite. Subbituminous coal, which comprises about 72 percent of the Western region's demonstrated reserve base, has a heat content ranging from 8,300 to 11,500 Btus per pound; bituminous coal accounts for about 17 percent of the western demonstrated reserve base and lignite, about 11 percent. Lignite has a heat content ranging from 6,300 to 8,300 Btus per pound.

Sulfur and ash contents are undesirable properties. Sulfur contributes to corrosion, to the formation of boiler deposits, and to air pollution. Overall, western coal is appreciably lower in sulfur content compared to coal found in the Central and Eastern regions. ^{11/} Ash and moisture content vary according to coal types but generally western coal has a higher moisture content than eastern coal, while ash contents vary within each region.

The sulfur content of coal has become important in recent years, with the enactment of air quality legislation and controls. As noted in chapter 2, increased reliance on low-sulfur coal has shifted some demand to new mines of low-sulfur coal in the West. As discussed in chapter 6, future environmental concerns over clean air are expected to bring a sharper focus on the regional distribution of coal reserves largely driven by reserve quality differences, particularly sulfur content.

In terms of conversion into synthetic fuels, some coal is also more desirable than others for conversion into synthetic fuels because of physical properties. Under current technology, western coal is more desirable than eastern

coal due to its noncaking* attributes when subjected to intense heat and pressure. Eastern coal requires costly pretreatment in order to minimize its caking characteristics. 12/

PROBLEMS RELATED TO THE DETERMINATION
AND RECOVERABILITY OF U.S. COAL
RESOURCES AND RESERVES

Reliability and usefulness of
reserve estimates

The usefulness of existing coal resource and reserve estimates varies according to the purpose for which they are used. In broad terms, the estimates do provide a rough idea as to the size of the Nation's coal inventories from which present and future production potential can be projected. In specific terms, the reserve estimates are of crucial importance when assessing coal as an alternative energy source. That is, given current and expected future coal (and substitute fuels) prices, reserve estimates ought to tell decisionmakers how much coal is and will be available. 13/ There are, however, grounds for questioning the reliability and usefulness of current coal estimates in terms of their use for specific decisionmaking purposes. 14/ Our study indicates that available data do not permit a useful delineation of U.S. coal reserves.

Furthermore, since coal must compete with other energy sources, a decisionmaker must know the total cost of converting coal to energy in order to make a choice. One part of this total cost is the extraction or mining cost. Current reserve estimates are based on the assumption that only a portion of the demonstrated reserve base will actually be mined due to technological, economic, or legal constraints. This condition occurs because not all of the demonstrated reserve base can be economically (profitably) recovered with current technology under current cost (price) conditions. 15/

Some reserves are not mineable at specific locations because of several factors. In the Eastern and Central regions, most of the mining to date has been accomplished in

*Caking coals, when heated, pass through a plastic stage and cake or stick together into a mass and, as a result, do not combust fully and clog the system.

areas where multiple seams of coal are present. For economic reasons, it can be reasoned that the most profitable (least cost) seams of coal are mined first. This procedure often leaves the seams above and below unused. BOM counts unused seams as mineable, which may not necessarily be true. If the interval between a mined seam and an unused seam above or beneath it is not sufficiently thick, the unmined seam may be fractured and subsided to such an extent that the seam is not mineable under any conditions. Water seeping through fractures may make the roof unsupportable and, therefore, the seam is lost for mining. Yet these unmineable seams are still included in the demonstrated reserve base. 16/

In addition, seams of coal under populated areas, Federal- and State-owned forests, parks, reservations, airports, navigable rivers, and streams, etc., which are not legally mineable, are also included in the demonstrated reserve base. The land surrounding oil and gas wells is often not mineable as large blocks of coal have to be left standing to prevent the hazard of oil and gas seepage, but it, too, is included in the demonstrated reserve base. 17/

To account for the portions of the demonstrated reserve base which cannot be recovered, some estimates employ differential rates of recovery for the underground and surface-mineable demonstrated reserve base. Traditionally, these rates have been 50 percent for the underground demonstrated reserve base and 80 percent for the surface-mineable demonstrated reserve base. Debate surrounds the appropriateness of these recovery rates. Previous studies indicate that the amount of coal that can be recovered from a known deposit can vary from about 35 percent to 90 percent. 18/ Such a wide variation in recovery rates has raised questions as to the usefulness of current estimates at certain locations based on the generalized recovery rates of 80 and 50 percent. 19/

In addition to the above geologic factors, economics plays a major role in determining which reserves will actually be recovered. For example, the greater the depth at which reserves are recovered, the more costly is the operation. 20/ Reserves mineable by underground methods are influenced by factors other than reserves mineable by surface mining techniques. Among the important factors besides depth of seam in underground mining are thickness and consistency of coal seams, unsafe roof conditions, water deposits,

methane* liberation, and poor floor conditions. Such factors increase the hazards of mining, reduce mine productivity, and increase production costs. 21/

The distribution and severity of these factors for specific coal reserves is not systematically available in current publications. Cost conditions are handled vaguely. Common to most USGS and BOM publications is the reference to current costs without any definition of cost levels or the distribution of costs for underground reserves at specific locations. 22/ In commenting on this report, USGS stated that neither they nor BOM have the authority to obtain actual mining costs from industry. As presented in USGS and BOM analyses, cost conditions are assumed to be uniformly distributed on the basis of the criteria employed for delineating underground reserves by geological assurance, minimum seam thickness, and maximum depth of 1,000 feet with few exceptions at specific locations.

Available data, therefore, do not permit a useful delineation of reserves on the basis of economic costs at alternative depths of deposit nor on other conditions affecting productivity (costs) at specific locations. 23/

Surface reserves, on the other hand, are influenced by fewer cost factors with depth of overburden being the primary one. Generally, surface mining is economical when the depth of overburden to be removed is of a certain relation to the seam thickness of the coal to be recovered. This relation is normally expressed in terms of feet of overburden removed per foot of coal recovered, referred to as a stripping ratio.** What is considered to be an economical (profitable) stripping ratio is determined largely by technology in the form of earth moving equipment (shovels and draglines) although terrain characteristics also influence productivity levels. For example, in the Eastern region, an economic stripping ratio varies between 15:1 and 24:1. Stripping ratios considered economical in the Central region vary from 15:1 to

*Methane (commonly called natural gas) is a colorless, odorless, gaseous hydrocarbon and is formed by the decomposition of plant and animal matter, and occurs in pockets in underground coal mines, presenting the danger of fires and explosions.

**For example, a stripping ratio of 10 to 1 (10:1) means that, on an average, 10 feet of overburden have to be removed for each foot of coal recovered.

20:1, while in the Western region they range between 1.5:1 to 30:1. 24/

Available data give some indication of economic stripping ratios but only at the State level. As currently compiled, the data do not present calculations of stripping ratios at specific coal deposits, making it difficult to identify and delineate surface mineable reserves on a cost basis.

In addition to questioning the reserve estimates on an economic basis there is some concern as to the validity of the data sources used to derive coal estimates. The methodology used by the USGS and BOM relies heavily upon secondary sources. Examples of secondary data sources include publications by State geological surveys, drilling records of coal mining companies, petroleum exploration firms, and/or water-well drilling companies, information in the files of State coal mine inspectors, and private records obtained from individuals. 25/ Coal reserve estimates obtained from coal companies and other proprietary sources are possibly understated due to incentives to avoid property taxes. Many States and political subdivisions within States where coal deposits are vast derive substantial tax revenues from property taxes levied on mineral deposits. Although the tax incentive may bias reserve estimates, the exact magnitude of the underestimation is not known. 26/

Although a uniform set of criteria has been adopted recently by the USGS and BOM for measuring resources and reserves 27/, the application of such criteria to such diverse secondary data sources, without analysis, may result in adding together dissimilar data bases. Much of the secondary data used by USGS was accumulated in the early 1900s and has not been refined since that time. 28/

Previous studies have shown that there are inherent limitations of coal resource and reserve estimates currently available at the USGS and BOM. 29/ Alternatives that have been discussed to improve the reliability and usefulness of the estimates include: 30/

--Stratigraphic drilling and mapping.

--Submission of coal reserve estimates by companies, including some degree of verification.

These could generate a more accurate picture of useable coal reserves. This is particularly important in the Eastern and Central coal regions where current estimates date back to the earlier part of this century. Since coal production could be quite significant in these regions, it is important

that a reliable coal reserve estimate be obtained. A substantial revision in estimates of the quantity and quality of eastern coal fields would have an impact on the level and need for investments in western coal mines and transportation facilities. Furthermore, if refined resource estimates indicated that Eastern and Central utility markets could be supplied with low-sulfur reserves from eastern coal fields, the Federal coal leasing program in the West could be modified accordingly.

There are some problems relating to the legality and the efficacy of a federally funded stratigraphic drilling program. One potential legal problem is the authority of a Federal agency to explore and conduct drilling programs on privately owned lands, particularly in eastern coal fields. In eastern coal fields, surface as well as mineral rights are largely privately held. Although no comprehensive study of eastern coal ownership rights has been undertaken, available evidence indicates widespread private ownership in the Central and Eastern fields. In the Western coal region, ownership is less of a problem since the Federal Government owns about 70 percent of the mineral rights of coal-bearing lands west of the Mississippi River. The Government's ownership pattern of western coal lands has the potential of influencing the development of another 20 percent of western coal-bearing lands (owned by States, railroads, and individuals) bordering on Federal lands. 31/

In the Northern Great Plains States of Montana, North Dakota, South Dakota, and Wyoming, the Federal Government owns about 14 percent of the surface rights and about 60 percent of estimated coal reserves underlying about 91.6 million acres (143,125 square miles) of coal-bearing lands. These four States own 5.4 percent of the remaining surface area and 6.3 percent of all mineral rights. 32/ Federal drilling in these coal-rich States is less constrained by ownership, and in fact, exploratory drilling by the USGS on Federal lands is authorized under recently enacted Federal Coal Leasing Amendments Act of 1975 (Public Law 94-377), prior to additional leasing of Federal coal lands.

Cost of conducting a stratigraphic drilling program depends on several geologic and economic factors. For example, in fiscal year 1976, the USGS's coal exploratory drilling program was funded for \$1 million with which 500 holes were drilled at an average cost of \$2,000 per hole. For fiscal year 1977, the Survey's drilling program is funded for \$2.5 million with which 1,255 holes are to be drilled. USGS's drilling program has been and will continue to be heavily concentrated in Montana, Wyoming, and North Dakota; these States include about 75 percent of all USGS drilling activity. The average cost of drilling per

vertical foot varies according to terrain condition (flat, hilly) and depth and composition of overburden. These costs vary in the Western States from a low of \$2.35 per foot to a high of \$25 per vertical foot. ^{33/} In the Central and Eastern regions, these costs range from \$11 to \$15 per foot. ^{34/}

Given probable legal constraints, if a systematic nationwide drilling program were to be undertaken, it is likely that new Federal legislation would be required to allow such activity on private lands, particularly in the East and Midwest.

The second means of refining resource and reserve estimates--submission and verification of privately held records--would serve to enhance data reliability at a lower cost compared to a comprehensive or select drilling and mapping program. However, this approach may not produce data for large areas of coal-bearing lands as not all coal lands throughout known coal fields have been previously explored and drilled. To produce meaningful results, a verification program would also likely require limited drilling and mapping of unexplored coal fields which may hold large quantities of desirable (low-sulfur) coal. To gain the cooperation of industry and minimize legal delays, incentives or legislative changes may be useful. An example of an incentive would be a Federal tax credit to firms that developed and reported their coal reserve holdings according to specified criteria.

Sulfur content of coal resources and reserves

Under existing Federal and State air quality standards, coal consumers are limited to using coal with low-sulfur levels, reducing sulfur contents before combustion (washing and blending) or removing emissions following combustion. Accordingly, a crucial question is whether there are sufficient supplies of low-sulfur coal to satisfy our energy needs from coal through 2000. Because control technology currently available for removing sulfur from coal before combustion increases capital and production costs, electric utilities are generally inclined to choose low-sulfur coal to reduce or eliminate the problem of removing emissions following combustion using current control technology.

Sulfur occurs in coal in the form of organic sulfur and as pyritic sulfur. The former is bonded in the coal and cannot be removed by mechanical washing while some pyritic sulfur can be removed. A recent BOM study based on 455 U.S. coal samples

concluded that current coal-cleaning technology will not significantly increase the amount of coal which can be directly burned in accordance with Federal new source performance standards promulgated under the Clean Air Act amendments of 1970 (Public Law 91-604)--1.2 pounds of sulfur dioxide per million Btus. 35/

Current estimates of low-sulfur coal are mostly made in the context of the demonstrated reserve base. The sulfur content of the remaining identified resources is not accurately known. 36/ Estimates of low-sulfur coal reserves may not be reliable to the degree desired for long-term national energy planning but they do give some idea as to their gross availabilities. BOM estimates reveal that about 31 percent of U.S. reserves, or about 78.9 billion tons, can be used for direct combustion and meet Clean Air Act standards without being cleaned prior to combustion. Of the estimated 78.9 billion tons, 8 billion are located in the Eastern region, .3 billion tons are in the Central region, and 70.6 billion (89 percent of the total estimate) are in the Western region. Table 2 delineates estimated reserves by region of location, method of mining, and pounds of sulfur dioxide per million Btus. 37/

Two Western States--Montana and Wyoming--have about 80 percent of the country's 78.9 billion tons of low-sulfur coal, according to BOM estimates. Montana alone is estimated to have about 69 percent of the Nation's known reserves of low-sulfur coal, according to BOM data.

The regional distribution of low-sulfur reserves presents a dislocation in terms of both future coal production and coal use. That is, a large portion of these reserves is located in the Western region and is a considerable distance from traditional coal consuming centers, particularly the Eastern United States, and new coal consuming areas in the Southern and Southwestern United States. 38/

Table 2

Analysis of Recoverable Coal Reserves by Sulfur
Content (Pounds of Sulfur Dioxide Per Million Btus)
As of 1975 (note a)

	<u>0-1.2</u>	<u>1.2 - 1.65</u>	<u>1.65 - 2.05</u>	<u>2.05+</u>	<u>Unknown</u>	<u>Total</u>
	----- (million tons) -----					
<u>Eastern Region</u>						
Underground	5,703	3,877	2,269	18,702	10,303	40,854
Surface	2,290	1,405	490	3,482	5,127	12,794
Total	<u>7,993</u>	<u>5,282</u>	<u>2,759</u>	<u>22,184</u>	<u>15,430</u>	<u>53,648</u>
<u>Central Region</u>						
Underground	271	459	633	26,228	12,315	39,906
Surface	39	133	161	9,820	3,884	14,037
Total	<u>310</u>	<u>592</u>	<u>794</u>	<u>36,048</u>	<u>16,199</u>	<u>53,943</u>
<u>Western Region</u>						
Underground	37,441	6,118	1,777	5,749	14,430	65,515
Surface	33,157	8,834	5,142	18,409	17,064	82,606
Total	<u>70,598</u>	<u>14,952</u>	<u>6,919</u>	<u>24,158</u>	<u>31,494</u>	<u>148,121</u>
<u>United States Total</u>						
Underground	43,415	10,454	4,679	50,679	37,048	146,275
Surface	35,486	10,372	5,793	31,711	26,075	109,437
Total	<u>78,901</u>	<u>20,826</u>	<u>10,472</u>	<u>82,390</u>	<u>63,123</u>	<u>255,712</u>

a/The following recovery factors were used: underground, 50 percent;
surface, 80 percent. Anthracite excluded from reserve estimates.

Assuming no change in current pollution standards, low-sulfur coal will most likely be used to a great extent to meet air pollution standards. Table 3 shows a comparison of low-sulfur coal reserves and cumulative demand requirements for the scenarios. As shown in the table, we can surmise that known estimates of low-sulfur coal reserves will be depleted by almost one-third by the year 2000 (column 5 in the table) if low-sulfur coal is the only coal used to satisfy added coal demand.

Assessing the adequacy of low-sulfur reserves must also take into account the reserves of metallurgical coal which, among several unique qualities, has low-sulfur content. ^{39/} The major use of metallurgical coal (also called "met coal" or coking coal) is production of coke, an essential ingredient in the manufacturing of iron and steel. ^{40/} Coke is usually made from blends of several metallurgical grade coals which are broadly classified as either premium-grade coking coal or marginal-grade coking coal. ^{41/} According to BOM, premium-grade coking coal, as generally accepted, contains no more than eight percent ash and one percent sulfur when mined or after conventional cleaning. Marginal-grade contains between 8.1 and 12 percent ash, and between 1 and 1.8 percent sulfur. ^{42/} Coking coal used for metallurgical coke production must have relatively small amounts of ash and sulfur, as all of the ash and a large portion of the sulfur remain in the coke and can reduce the quality of the metals. ^{43/} Reduction of ash and sulfur in the metallurgical process is essential and costly. ^{44/}

The broad classifications of premium-grade and marginal-grade metallurgical coals are further distinguished by the amount of fixed carbon and volatile matter* they contain. ^{45/} BOM classifies coal as low-volatile if it contains from 14 to 22 percent volatile matter and medium-volatile if it contains 22 to 31 percent. ^{46/} Low-volatile metallurgical coal included in a coal blend serves to increase the yield of a coke manufacturing operation, and to produce a higher strength coke, with slow-burning, even-heat advantages for steel manufacturing and other high-value uses. BOM reports that as yet there are no accurate estimates of coking coal reserves, but prior Bureau reports have indicated that about 20 billion tons of the demonstrated bituminous coal reserve base of 233 billion tons consists of premium-quality coking coals. ^{47/} An assessment by BOM indicates that about 7 billion tons is low-volatile coking coal. ^{48/}

*Volatile matter consists mainly of combustible gaseous hydrocarbons but includes some inert gases such as carbon dioxide.

Table 3

Comparison of Low-Sulfur Coal Reserves
and Demand Levels (1976 to 2000)

<u>Scenario</u>	<u>1976 to 1985</u>			<u>1986 to 2000</u>	
	(1)	(2)	(3)*	(4)	(5)**
	<u>Low-sulfur coal reserves</u>	<u>Cumulative coal demand</u>	<u>Remaining low-sulfur coal reserves</u>	<u>Cumulative coal demand</u>	<u>Remaining low-sulfur coal reserves</u>
	----- (million tons) -----				
Bureau of Mines	78,900	7,378	71,522	19,036	52,486
Edison Electric Institute	78,900	6,488	72,412	12,872	59,540

*Column (3) equals column (1) minus column (2)

**Column (5) equals column (3) minus column (4)

Coking coal occurs in about 20 States, but it is estimated that at least 90 percent of all coking coal is in the Eastern region. West Virginia has, by far, the largest quantities of both premium- and marginal-grade coal, followed by Pennsylvania and Kentucky. Kentucky coking coal, however, has high-volatile matter content while Pennsylvania has high-volatile as well as undetermined quantities of medium- and low-volatile coking reserves. Known deposits of low-volatile coking coal occurs only in West Virginia, Pennsylvania, Virginia, Maryland, Arkansas, and Oklahoma. 49/ The lack of accurate and reliable data regarding premium-grade coking coal has fostered a controversy concerning how much low-volatile premium-grade coal is produced and exported, and whether these exports will affect unfavorably our future domestic steel production capabilities. 50/ In 1976, about 250 million tons of metallurgical coal were produced. Of that amount, 90 million tons were used by the domestic steel industry, and 50 million tons were exported, leaving some 110 million tons for other uses, most likely by electric utilities in search of low-sulfur coal. 51/

Although metallurgical coal requirements were included in the above analysis of the adequacy of low-sulfur reserves, it should be noted that market pressures may restrict the use of metallurgical coal deposits by electric utilities. For example, recent data show the average (spot market) price (FOB mine) range of metallurgical coal to be \$26 to \$50 per ton as compared to an average price range of about \$7 to \$20 per ton for steam coal. 52/ Because of these price differentials, the steel companies who own substantial amounts of metallurgical coal reserves may continue to be the principal users.

The data, as indicated above, reveal that about 110 million tons of metallurgical coal may have been consumed by electric utilities in need of environmentally acceptable low-sulfur coal. We were unable to determine whether this coal was of premium-grade quality since official data are not available, making it speculative whether this represents a future trend. Availability of acceptable environmental control technologies and potential Federal requirements for their use at electric utilities could reduce the demand for low-sulfur coal.

Recoverability of reserves

Coal can be mined by three techniques--underground, surface, and auger mining. Auger mining is essentially a form of surface mining. On an economic basis, surface mining offers significant cost advantages over underground

mining. Over the past several years, the Congress had debated and passed legislation, which was subsequently vetoed, on setting standards for surface mining and reclamation. The 95th Congress and the new administration placed a high priority on controlling surface mining, which resulted in passage on the Surface Mining Control and Reclamation Act of 1977 (P.L. 95-87). 53/

Surface mining has received national attention because of its adverse environmental impacts. These impacts can be reduced by regulating the coal industry's surface mining activity. The nature of these adverse environmental impacts is discussed in chapter 6.

The recently enacted surface mining legislation (P.L. 95-87), prohibits mining of certain coal reserves because of the potential adverse environmental effects during and after mining operations. Among the restricted areas are:

- Alluvial valley floors,
- Steep slopes,
- Federal lands where surface owners' rights are protected.

P.L. 95-87 contains an alluvial valley floor restriction which will eliminate some reserves from being mined. However, it allows for the continuation of current mining operations producing coal in commercial quantities in the year preceding enactment of the law, or which had obtained permit approval by State regulatory authorities. 54/ Alluvial valley floors consist of unconsolidated deposits formed by streams or channels where ground-water levels are high enough to permit irrigation which is vital to farming and ranching operations. 55/ As defined in P.L. 95-87, the restriction would affect parts of Montana, Wyoming, North Dakota, Utah, and Colorado. Recent studies indicate that the amounts of surface areas and coal reserves affected by the restriction in these regions would be small--only about 3 percent of the surface area. 56/ One study concluded that perhaps .6 to 2.4 billion tons of surface-mineable reserves may be restricted in order to protect alluvial valley floors in agriculturally developed areas, a small amount when compared to the vastness of western surface-mineable reserves. 57/

Surface mining restrictions based on the angle of the slope overlying coal reserves are also provided in

P.L. 95-87. The act defines a steep slope to be any slope above 20 degrees, or such lesser slope as may be defined by regulatory authority (the Secretary of the Interior or the State involved) after considering regional environmental and geological factors. 58/ For all practical purposes, the Eastern region areas of southern West Virginia, eastern Kentucky, Virginia, and eastern Tennessee would be affected most by steep slope reserve restrictions. However, accurate estimates of economically recoverable reserves lost to mining by the steep slope restriction are not available. Technological advances in the practice of mountaintop removal* may permit recovery of some reserves under steep slopes at certain locations 59/ in an environmentally acceptable manner. 60/

Public Law 95-87 also provides protection to owners of surface rights overlying federally-owned coal. Written consent from surface owners must be obtained by the Secretary of the Interior before such land can be leased for surface mining. 61/ No accurate estimate exists as to the amount of Federal coal mineral rights that is overlain by non-Federal surface rights. One study indicates that as much as 14 billion tons of coal could be prohibited from surface mining under this provision in the seven-State region consisting of Colorado, Montana, New Mexico, North Dakota, Oklahoma, Utah, and Wyoming. 62/ This highly uncertain estimate indicates the need for more reliable and accurate reserve data on Federal coal lands.

Recoverability of coal resources at some locations may also be reduced because of incremental mining costs associated with reclamation and restoration requirements in the act. The act (1) prohibits leaving "highwalls"--nearly vertical overburden formations similar to highway corridors cut through mountains--after reclamation; (2) imposes strict criteria for mining steep slopes, generally found in Appalachia, including the prohibition of placing overburden on hillsides in order to prevent landslides and other environmental damage; (3) minimizes disturbances to the prevailing hydrologic balance in surface

*Mountaintop removal mining is practiced where coal seams are close to the tops of mountains. This technique is the most economical method of mining these coal deposits and requires the removal of all overburden covering the coal seam.

and ground-water systems during and after mining operation activities at the mine site and associated areas; and (4) requires that mined land be restored to its approximate original contour with exceptions for mountain-top removal operations and other variances permitted by the act. 63/ Public Law 95-87 also establishes a fund to reclaim abandoned mined lands financed by a 35 cents per ton fee on all surface-mined coal* and a 15 cents per ton fee on deep-mined coal or 10 percent of the value of the coal at the mine gate, whichever is less. 64/

These reclamation and restoration requirements will increase the cost of mining coal at specific locations. Some States already impose reclamation and restoration requirements similar to the Federal regulations. 65/ The major cost element for most surface mining reclamation operations is the cost of handling overburden. When backfilling and regrading is performed to restore terrain to its approximate original contour, mining costs increase as a result of more extensive rehandling of overburden. 66/ Operating costs as well as capital costs per ton of coal recovered will be increased since additional labor and equipment will be required to reclaim and restore the terrain disturbed during mining operations. Although no accurate estimate of these incremental costs on a per ton basis by region is available, a recent study indicates wide variations in reclamation (operating) costs per acre for existing mines, ranging as high as \$4,895 (1976 dollars) on near-level terrain to \$7,743 (1976 dollars) on steep slopes, and up to \$11,125 (1976 dollars) on very steep slopes. 67/

Because cost variations can range widely it is difficult to determine with accuracy the magnitude of surface-mineable resources affected by P.L. 95-87 at various levels of coal demand and prices. However, the impact will vary from one location to the next as terrain, technological, geologic, and economic conditions differ.

*The reclamation fee for lignite coal is 2 percent of the value of the coal at the mine gate, or 10 cents per ton, whichever is less.

Implications of Federal coal ownership

The Government is in a good position to influence the recoverability of coal reserves due to its control over much of the mineral rights in the Western United States. In the States west of the Mississippi River, the Government owns about 70 percent of the coal and can influence the development of another 20 percent bordering on Federal lands. In addition to its western holdings, the Government owns about 4.6 million acres of coal land in Alabama, Arkansas, Kentucky, Mississippi, and Virginia.

Western coal has assumed an important role in this Nation's coal development because (1) it is generally easier and more economical to produce because it is surface-mineable and it occurs in very thick seams, (2) western lands are usually easier to obtain in large tracts than eastern lands and, therefore, can be more efficiently mined, and (3) western lands are rich in deposits of low-sulfur coal. 68/

Under the Mineral Lands Leasing Act (30 U.S.C. 181), and the Mineral Leasing Act for Acquired Lands (30 U.S.C. 351), the Federal lands containing coal deposits may be leased for mining coal. The Government has currently issued leases for coal deposits thought to contain an estimated 17.3 billion tons of reserves. There are an additional 10.3 billion tons under Preference Rights Leasing Applications. 69/ However, the cumulative coal production on Federal lands was only about 380 million tons through 1976. 70/

The Department of the Interior's (DOI) estimate of 17 billion tons of reserves under lease is at best a rough and conservative approximation of the actual resources under lease. The reliability of the estimate is questionable because most of the information used in arriving at it is based on 1973 conditions, a time at which coal market (FOB mine) prices were considerably lower than those observed today. 71/ The higher prices, particularly if they are anticipated to remain at or above current levels in relation to production and transportation costs, have the potential impact of increasing the amount of recoverable reserves on coal lands currently under Federal lease. At higher prices, identified resources which were not considered to be economically recoverable may now be recovered profitably. If higher prices expand reserve estimates, this might obviate the need for new Federal leasing, at least on a temporary basis, as demands for low-sulfur western coal increase. With accurate information on coal reserves, Federal decisionmakers could choose either to

lease more Federal land or to maintain the current number of leases and promote higher future production levels. Additional information is also needed as to the role of non-Federal coal in western coal development before responsible Federal leasing policies can be formulated.

Coal reserves under Federal lease and associated issues surrounding Federal coal leasing policy are currently being reviewed in an ongoing study by our Office. Our study will analyze 250 of the 536 current leases, representing about 65 percent of DOI's estimate of reserves under lease, as of December 1975. Preliminary findings show that of the 250 leases, 130 are in some stage of development, indicated by either an approved mining plan, a mining plan under DOI review, or a mining plan in preparation. These preliminary findings, particularly if they remain consistent for the balance of the leases to be audited, indicate an expanding role of Federal coal in the Nation's total energy picture.

In summary, at this time, the extent of the need for new Federal coal leasing is unclear, due to the little information on the current reserve situation and the many policy options affecting Federal coal leasing.

In addition to coal deposits on Federal lands administered by the Bureau of Land Management, there are sizable quantities of coal resources on Indian reservations. The Bureau of Indian Affairs is responsible for all phases of management of minerals on Indian lands through the leasing process. Although an accurate estimate of coal resources on Indian lands does not exist, the USGS has estimated that 33 reservations in 11 States, spread over a total of 34.5 million acres, contain from 100 to 200 billion tons of identified coal resources. ^{72/} These resources on Indian lands represent about 7 to 13 percent of the Nation's identified coal resources. Available estimates of the coal reserves on Indian lands are limited to leased Indian lands only and have been estimated to be about 5.4 billion tons. About 3.5 billion tons are considered recoverable, as of March 1975. ^{73/}

Currently, five coal mines are operating on Indian lands. Two are located in Arizona on joint-use land of the Navajo and Hopi Tribes; two are in New Mexico on Navajo land, and one mine is operating on land leased by the Crow Tribe in southeastern Montana.

In terms of western coal development, Indian coal lands are available in large tracts not subject to checkerboard surface-ownership patterns which characterize vast amounts of federally-owned coal lands in the Northern Great Plains.

This checkerboard ownership pattern has been said to delay the consolidation of logical mining units on Federal coal lands because public hearings can be requested under Public Law 94-377 before the Secretary of the Interior can approve consolidation. For these reasons, Indian coal lands now under lease or potentially leaseable may become more attractive to western coal developers.

SUMMARY

As of January 1974, there were 3.9 trillion tons of coal resources in the United States. Of this, 1.7 trillion were classified as identified resources.

Coal resources which can be mined given current technological, economic, and legal constraints are termed reserves. U.S. coal reserves are about 256 billion tons and represent 90 percent of the Nation's fossil fuel reserves.

Under the high coal demand forecast in this report--an annual coal growth rate of 3.69 percent--today's known coal reserves will satisfy demand for about 74 years.

Coal in the Eastern and Central regions has a higher heat content than most found in the West. But overall, western coal is appreciably lower in sulfur content.

Available data do not permit a useful delineation of reserves on the basis of economic costs at alternative depths of deposit nor on other conditions which affect productivity (costs) at specific locations. Available data give some indication of economical stripping ratios (ratio of overburden to coal) but only at the State level. In addition, the reserve estimates of the USGS and BOM are questionable because they rely so heavily upon secondary sources. Coal reserve estimates obtained from coal companies and other proprietary sources are possibly understated due to incentives to avoid property taxes. The exact magnitude of the underestimation is not known.

The usefulness and reliability of coal data could be advanced by federally-sponsored stratigraphic drilling and mapping, and by verification of coal company reserve estimates. Given probable legal constraints, if a systematic nationwide drilling program were to be undertaken, it is likely that new Federal legislation would be required to allow such activity on private lands, particularly in the East and Midwest.

A substantial revision in estimates of the quality and quantity of eastern coal fields (current estimates date back to the earlier part of this century) would have an impact on the level and need for investments in western coal mines and transportation facilities. The timing of Federal coal leasing would also be affected.

A specific problem of coal resource and reserve estimate reliability is whether there are sufficient supplies of low-sulfur coal to satisfy the demand through the year 2000. Generally, electric utilities are inclined to choose low-sulfur coal to reduce or eliminate the problem of removing emissions following combustion using current control technology.

BOM estimates that about 31 percent of the Nation's coal reserves can be used for direct combustion and meet Clean Air Act standards. About 89 percent of this coal is in the West. Wyoming and Montana account for 80 percent of the Nation's low-sulfur coal.

BOM reports that as yet there are no accurate estimates of the Nation's metallurgical coal reserves; this coal is used to produce coke, an essential ingredient in the manufacturing of iron and steel. The lack of accurate and reliable data regarding metallurgical coal, especially premium-grade metallurgical coal, has fostered a controversy concerning exactly how much premium-grade metallurgical coal is produced and exported and whether these exports will unfavorably affect the Nation's future domestic steel production capabilities.

Recent surface mining legislation partially restricts surface mining in alluvial valley floors or on steep slopes. Recent studies indicate that the coal reserves affected by the alluvial valley prohibition would be small. No accurate estimates exist, however, concerning reserves under steep slopes.

The legislation also provides for the protection of surface owner rights on Federal coal lands. One study indicates that as much as 14 billion tons of coal could be prohibited from surface mining under this provision in the 7-State area of Colorado, Montana, New Mexico, North Dakota, Oklahoma, Utah, and Wyoming. This estimate, it should be noted, is highly uncertain, indicating the need for more reliable and accurate data on Federal coal lands.

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66/Ibid., p. II-29.

67/Ibid., p. II-41. ICF reports these cost in 1978 dollars, but we converted the costs to 1976 dollars using conversion table on page II-4 of the ICF study. Due to the Federal requirements, the study estimated the highest incremental operating costs to occur in Virginia and Alabama because of steeper slopes. These States are followed by eastern Virginia.

- 68/United States General Accounting Office, Role of Federal Coal Resources in Meeting National Energy Goals Needs to be Determined and the Leasing Process Improved, RED-76-79 (Washington: U.S. General Accounting Office, April 1, 1976), p. 2.
- 69/United States Department of the Interior, Bureau of Land Management, Final Environmental Impact Statement on Proposed Federal Coal Leasing Program, op. cit., p. I-81.
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- 72/United States General Accounting Office, Indian Natural Resources -Part II: Coal, Oil, and Gas Better Management Can Improve Development and Increase Indian Income and Employment, RED-76-84 (Washington: U.S. General Accounting Office, March 31, 1976), p. 2.
- 73/Parker and Thompson, op. cit., pp. 7 and 9.

CHAPTER 4

HOW DO WE GET IT?

Our reference scenarios of future energy needs forecast that annual coal production will be from 779 to 988 million tons by 1985 and from 942 to 1,586 million tons by the year 2000. The importance of these projections is apparent when examining recent production data. During 1975 bituminous and lignite coal production in the United States amounted to 648 million tons. 1/ The coal industry employed an average of 189,880 miners of which 134,710 worked in underground mines and 55,170 in surface--strip and auger--mines. 2/ As estimated by the Bureau of Mines, 665 million tons of coal were produced in 1976, and average employment increased to 208,000 miners. 3/

The expected growth in the coal industry within the 25-year period of 1975 to 2000 is important. Achieving the forecasted production goals will require the following:

- Opening 438 to 825 new mines.
- Recruiting and training 288,300 to 531,600 new miners.
- Manufacturing considerable quantities of mining equipment for underground and surface mines.
- Securing \$26.7 to \$45.5 billion in capital.
- Continuing research and development efforts by BOM, the Mining Enforcement and Safety Administration (MESA), and the coal industry to improve mining safety and health conditions and increase productivity levels.

To determine the potential problems in achieving these goals, our review of coal production addressed the following matters.

- Coal industry plans for opening and operating new mines needed to satisfy future coal production.
- The number of qualified personnel needed to produce the coal.
- The equipment needed to achieve coal production goals.

Note: Numbered footnotes to ch. 4 are on pp. 4.60 to 4.71.

- The capital required to meet expected development needs.
- The possible horizontal divestiture by oil companies of coal interests and their related impact on capital availability to coal mining.
- The impact of the Federal coal mine loan guarantee program on capital availability.
- Legislative and tax impacts on current and planned coal mine operation and expansion.
- Research and development efforts being made currently and contemplated for the future to improve mine health and safety conditions and to increase productivity.

The nature of the coal industry and the outlook for coal production and potential problems are discussed in the following sections.

DESCRIPTION OF THE COAL INDUSTRY

There are three types of coal mine operations: 4/

- Mine operations (captive mines) belonging to utility, metal, and mineral companies, which are generally large in size.
- Major diversified corporation holding companies, multiproduct, and multinational corporations, (including oil companies) for which coal mining is one of several interests.
- Independent companies with coal as their primary product.

Business structure

A study by BOM, "The State of the U.S. Coal Industry," issued in 1976, points out that there have been great changes in the structure and behavior of the industry. The report stated that the producers started out as small companies. Until recently, because of the vigorous competition from natural gas and oil, the coal industry has not experienced any sustained growth, although there was a brief expansionary period during and shortly after World War II. The promise of nuclear energy in the early 1960s further limited the market outlook for coal. The report concluded,

"Accordingly the industry which was extremely fragmented with about 5,000 companies (few large and many small) made little capital investment in new mines, expansion and improvement of existing mines, or purchase of machinery."

In the 1960s other resource-based companies, especially major oil companies, moved to purchase coal-producing companies and acquired coal reserves through outright purchase and lease. In testimony on April 5, 1977, before the Senate Committee on Energy and Natural Resources, the President of the National Coal Association stated that coal companies controlled by oil interests now own roughly 18 percent of U.S. coal reserves. Most of the large companies (annual production of more than 3 million tons) became subsidiaries or affiliates of major oil companies, utilities, steel companies, or other mineral resource producers. Nearly all of the top 15 coal producers are in this category.

Major steel, public utility, chemical, and metal companies have accelerated their move toward coal self-sufficiency and, like the oil companies, are aggressively acquiring small coal companies and coal reserves. Although several small coal companies were formed and existing companies added coal ventures as their principal line of business, the trend has been toward fewer but larger companies. 5/

The BOM report points out that today's coal mines use costly mining equipment. Additional expensive machinery must also be installed to meet regulatory standards for health, safety, and environment. Opening new mines and expanding existing ones requires enormous amounts of capital and takes a long time. 6/

The report further states

"The number of small companies will no doubt continue to decline owing to increased cost of operations and difficulties in attracting new capital for mine improvement and expansion, purchase of mining equipment, and opening of new mines. The long leadtime for completion, coupled with the full impact of expenses of the 1969 Coal Mine Health and Safety Act, compounds this difficulty. Moreover, many of the natural resource-based companies have accelerated their acquisition program of coal reserves and small producers." 7/

BOM estimates that there are about 3,900 companies, including subsidiaries, producing coal. Of these, 597

companies account for 94.5 percent of the national coal production. The remaining 3,303 companies each produce less than 100,000 tons of coal per year, or about 8,000 tons per month, and represent approximately 5.5 percent of the national total. Those companies producing less than 100,000 tons of coal per year account for a smaller portion of total production--declining from 17.8 percent in 1949 to 5.5 percent in 1974. A summary of coal producers, by size, is shown in the following table. 8/

Table 1

Number of Coal Companies in 1974

by Size and Production

<u>Size class</u>	<u>Number of companies</u>	<u>Production</u> (thousands of tons)	<u>Percent of total production</u>
3,000,000 tons and over	31	347,437	57.8
1,000,000 - 2,999,999 tons	42	78,489	13.0
500,000 - 999,999 tons	59	40,740	6.8
100,000 - 499,999 tons	465	101,759	16.9
Less than 100,000 tons	<u>a/3,303</u>	<u>32,575</u>	<u>5.5</u>
Total	<u>3,900</u>	<u>b/ 601,000</u>	<u>100.0</u>

a/Estimated.

b/Preliminary.

In describing the coal market, the BOM report estimates that about 85 percent of all coal mined is sold domestically or exported under long-term contracts (5 to 30 years), or produced by captive mines; this leaves approximately 15 percent on the open market, known as the "spot" market. Both the long-term contract and spot markets are competitive in terms of price, service, and quality of product. In addition, they are subject to competition from other energy sources. 9/

PRODUCTIVITY

Initially, coal was obtained primarily by stripping and limited tunneling into the side of a hill (drift mines). In the drift mines, coal was undercut by hand and wedged down

until explosives came into general use. In the 1870s coal undercutting machines driven by steam and, later, compressed air were used to increase productivity. 10/

The era of underground coal mechanization and increased productivity began in the late 1930s. All major tools became powered and productivity rose in the 1940s from 4 to 6 tons per worker-day. In the 1950s production increased to 11 tons per worker-day. The late 1950s marked the beginning of a new machine called the continuous miner, and in the 1960s, after its use increased, productivity also increased to about 16 tons per worker-day. 11/

In the 1960s the introduction of longwall and shortwall mining equipment and techniques for controlled subsidence resulted in the increased recovery of available coal resources. The continuous miner room and pillar technique recovers only 50 percent of the available coal, while shortwall/longwall mining techniques can recover from 80 to nearly 100 percent of the available coal resources. 12/

Surface mine operations raised productivity through the development and greater use of drillers, bulldozers, haulers, scrapers, front-end loaders, shovels, bucket wheel excavators, and draglines. Further productivity gains occurred through increases in the size of coal equipment. The result of all these developments was a sharp increase in output per worker-day and an increased dependence on equipment. There was also a steady rise in surface mining which is inherently more productive. 13/

The following table highlights the changes in mining productivity that have occurred during the past 36 years. 14/

Table 2

Productivity and Mining Trends

Year	Productivity			Production		Total
	Underground	Surface		Underground	Surface	
		Strip	Auger			
	(tons per worker-day)			----- (million tons) -----		
1940	4.86	15.63		418	43	461
1945	5.04	15.46		468	110	578
1950	5.75	15.66		393	123	516
1955	8.28	21.12	22.22	344	121	465
1960	10.64	22.93	31.36	285	131	416
1965	14.00	31.98	45.85	333	179	512
1970	13.76	35.96	34.26	339	264	603
1973	11.66	36.30	45.33	299	292	591
1975	9.54	a/26.69		292	356	648
1976	8.50	b/26.00		296	369	665

(note b)

a/Strip and auger combined (see glossary for description of auger mining).

b/All 1976 figures are estimates.

Productivity has declined since 1969 especially in underground mines. This decline is attributable to many factors. BOM indicated the following among the principal causes.
15/

- Requirements of the 1969 Federal Coal Mine Health and Safety Act which increased the number of personnel in the mines.
- Changes in mining conditions such as the quality of mine roofs, types and widths of coal seams, distances from entrances of mines to the operating face, and overburden ratios and characteristics.
- Introduction of great number of inexperienced miners.
- Increased exploration activity by all companies, especially surface mines.
- Requirements for additional personnel in accordance with provisions of union agreements.
- Unscheduled interruptions in production caused by wild-cat strikes and absenteeism.

Effects of productivity on pricing

Increases in productivity, in part, allowed prices to remain stable in spite of inflationary trends in the 1950s and 1960s, but after 1970, prices rose steadily with a sharp increase in 1974. The following table shows the trend in mine-mouth prices and labor costs over the past 21 years.

16/

Table 3

Coal Prices and Earnings (note a)

Year	Average price per ton (FOB mine)			Hourly earning of Coal miners	Miners' earnings per ton of coal		
	Underground	Strip	Auger		Underground	Strip	Auger
1955	\$10.14	\$7.51	\$7.51	\$5.15	\$4.99	\$1.94	\$1.86
1960	9.53	6.93	6.25	5.82	4.37	2.04	1.48
1965	8.44	6.11	5.75	5.98	3.41	1.48	1.04
1970	10.31	6.53	8.47	6.38	3.70	1.42	1.32
1971	11.75	6.88	8.71	6.43	4.28	1.44	1.32
1972	12.34	6.97	8.32	6.81	4.57	1.52	1.27
1973	13.04	7.35	8.89	6.90	4.73	1.52	1.22
1974	21.71	b/13.39		6.80	6.62		1.65
1975	26.28	B/13.44		7.23	6.06		2.17
1976	27.10	B/14.00		N/A	N/A		N/A

(note c)

a/All data other than 1976 are in 1975 constant dollars.

B/Strip and auger combined

C/All 1976 figures are estimates.

Miners' earnings per ton of output are based on the overall average output per worker-day for each category in the years concerned, using the average wage rate shown. It should also be noted that the above prices represent average prices for the country. In 1975 the average price for surface-mined coal in North Dakota was \$3.17 per ton, in Montana \$5.06, in West Virginia \$24.04, and in Arkansas \$32.76. The average price for underground coal by State ranged from a low of \$10.62 in Iowa to a high of \$33.77 in Alabama. 17/ We assume that the differences in price are based mainly on production costs and the quality and grade of coal.

Comprehensive and up-to-date cost figures on coal production are not available from any of the sources we contacted during our review. The March 1976 study of coal prices performed by the Council on Wage and Price Stability pointed this out and noted that costs vary substantially among mines. They also pointed out that the average value per ton of coal rose much more rapidly than labor costs in 1974 and 1975. They concluded, "Unless all other costs have grown more quickly than labor costs (which appears doubtful), the average price has also outpaced total costs." A study of selected companies showed that from 1970 through 1973 profits declined and in 1973 the average net income was only 20 cents per ton. In 1974, prices rose and net profits rose to \$2.80 per ton or 18 percent of the average value per ton. 18/

In 1976 BOM prepared estimates of production costs for use in projecting capital requirements; the projections are based on the 1974 Bituminous Wage Agreement and 1975 prices indices. We did not verify the accuracy of the estimates but believe that they provide a reasonable basis for comparing production costs between various mine sizes and between surface and underground mines. These figures cannot be compared with the average price per ton since the average price represents all mine sizes regardless of location or degrees of mechanization. The BOM estimates of production costs are shown in table 4. 19/

Table 4

Mining Cost Comparisons

<u>Items or cost</u>	<u>Underground (note a)</u>				<u>Surface</u>		
Mine size in million tons per year	<u>1.06</u>	<u>2.04</u>	<u>3.18</u>	<u>4.99</u>	<u>4.8</u> (note b)	<u>6.72</u> (note c)	<u>9.2</u> (note d)
----- (cost per ton) -----							
Direct cost							
Production	\$2.39	\$2.17	\$2.07	\$2.08	\$.34	\$.26	\$.20
Maintenance	.37	.31	.28	.27	.14	.10	.09
Operating supplies	1.84	1.84	1.84	1.84	.74	.60	.45
Power	.38	.34	.32	.32	.26	.18	.12
Reclamation (note e)	-	-	-	-	.04	.04	.04
Payroll overhead	1.11	.99	.94	.93	.19	.14	.11
Union welfare	1.05	1.03	1.02	1.02	.80	.78	.77
Royalty	-	-	-	-	.50	.50	.24
Strip license and bond	-	-	-	-	.07	.09	(f)
Indirect cost	.69	.65	.63	.63	.18	.14	.11
Taxes and insurance	.33	.31	.30	.29	.25	.22	.08
Depreciation	<u>1.03</u>	<u>.86</u>	<u>.78</u>	<u>.74</u>	<u>.86</u>	<u>.77</u>	<u>.40</u>
Total	<u>\$9.19</u>	<u>\$8.50</u>	<u>\$8.18</u>	<u>\$8.12</u>	<u>\$4.37</u>	<u>\$3.82</u>	<u>\$2.61</u>

a/Millions of tons from a 72-inch coal bed.

b/Eastern United States--millions of tons from 6-foot seam.

c/Interior United States--millions of tons from 6-foot seam.

d/Northern Great Plains--millions of tons from 25-foot seam.

e/Contracted for mulching, liming, fertilizing, and seeding.

f/Royalty and strip license and rent combined.

A principal factor for the variation in productivity and cost between mines is the thickness of the coal seam. BOM estimates that the selling price for surface-mined coal varies considerably, based on the thickness of the seam. 20/

--Coal mined in the Eastern province* could sell at \$6.94 per ton from a 6-foot seam and \$11.63 per ton from a 3-foot seam.

--In the Interior province**, the coal from a 6-foot seam could sell at \$6.03 per ton and from a 3-foot seam at \$10.07 per ton.

--In the Northern Great Plains province***, the coal could sell at \$2.39 per ton from a 50-foot seam and \$6.58 per ton from a 10-foot seam.

All these prices assume a 15 percent rate of return after taxes and are exclusive of transportation cost, which is an important factor. In 1974 railroad freight charges averaged \$4.71 per ton, 21/ rising in 1975 to \$5.25 per ton. 22/ Rail transportation costs can vary from \$.47 per ton to a high of \$10.00 per ton. Many factors account for these extremes such as distance, type of train (unit train or mixed freight), and ownership of cars (utility or railroad). 23/

Additional production capacity

In 1975 over 648 million tons of coal were produced, and BOM estimates that existing operations could have produced a peak of 692 million, or 44 million tons more than were actually extracted. 24/ It is also estimated that between 10 and 60 million tons of additional coal could have been mined by small operators, those producing less than 200,000 tons each per year. These mines are generally profitable only during periods of high coal prices. It is usually during periods of peak coal demand that such mines operate. 25/

*Includes coal fields in Maryland, North Carolina, Ohio, Pennsylvania, Georgia, Virginia, eastern Kentucky, and parts of Alabama and Tennessee.

**Includes coal fields in Illinois, Indiana, Iowa, Kansas, Missouri, Michigan, Oklahoma, Nebraska, western Kentucky, and parts of Arkansas and Texas.

***Includes coal fields in North Dakota, South Dakota, and parts of Montana and Wyoming.

Opening of new mines

Great amounts of time and effort are required to perform the various tasks from conception until actual commencement of production. Because of the time required to open a new mine, supply of coal is flexible in the long run and constrained in the short run. The short run capacity of the industry is limited to what could be extracted through increased production (surge capacity) at existing mines. In other words, coal is usually demand-constrained in the long run and supply-constrained in the short run.

BOM has categorized the various tasks for opening new mines into the following steps. 26/

- Initial examination--including all those steps necessary to determine whether the coal should be mined.
- Mine assembly--including those steps necessary to determine how and in what manner the coal should be mined, the acquisition of the rights to mine the coal, and determination of the annual production.
- Cost analysis--determining the cost elements and performing an economic analysis on the profitability of mining the coal.
- Market development--including those steps necessary to secure a customer and negotiate the terms of the contract.
- Environmental and related studies--performing all the steps required to determine and report the environmental and socioeconomic effects of mining the coal.
- Preliminary design and equipment ordering--designing the mine, showing how the coal will be extracted, determining what equipment will be needed, and ordering the equipment.
- National Environmental Policy Act (NEPA) process--the steps taken by the Government when assessing the environmental impact of the mining of Federal lands.
- Permits--securing necessary State permission for use of water at the mine, for mining and reclamation operations, and for other regulatory requirements.

--Design and construction--preparing the final design of the mine, and constructing the mine and related facilities including access roads, rail line, and power supply.

--Mining preparation--the final stage before opening the mine, involving installation of mining, loading, and support equipment and personnel recruitment and training.

The following table shows BOM's estimates of the time required for each of the above steps, relating to surface and underground mines in the East and the West. The extent of effort and the time required to complete each step are influenced by the location of the mine, size of the intended operation, ownership type and pattern, and environmental considerations. Since some steps can be performed simultaneously with others, the total length of time may be less than indicated here.

Table 5

Time Requirements for New Mine Openings

	Surface				Underground			
	East		West		East		West	
	<u>Min.</u>	<u>Max.</u>	<u>Min.</u>	<u>Max.</u>	<u>Min.</u>	<u>Max.</u>	<u>Min.</u>	<u>Max.</u>
	----- (years) -----							
Initial examination	.10	.20	.15	.50	.10	.20	.10	1.50
Mine assembly	.15	.30	.25	1.50	.15	.30	.20	2.00
Cost analysis	.00	.10	.10	.50	.00	.25	.10	.50
Market development	.00	.15	.10	.50	.00	.15	.10	.50
Environmental and related studies*	.00	.10	.50	1.50	.00	.10	.25	1.50
Preliminary design and equipment selection	.50	.75	.50	1.50	.75	1.00	.50	1.00
NEPA process*	.00	.00	1.50	4.00	.00	.00	1.00	3.00
Permits*	.25	.50	.50	2.00	.25	.50	.25	1.50
Design and construction	.50	.75	.30	2.00	.75	1.25	.30	2.00
Mining preparation	<u>.00</u>	<u>.15</u>	<u>.10</u>	<u>.50</u>	<u>.50</u>	<u>1.25</u>	<u>.20</u>	<u>1.00</u>
Total	<u>1.50a</u>	<u>3.00</u>	<u>4.00</u>	<u>15.00</u>	<u>2.50</u>	<u>5.00</u>	<u>3.00</u>	<u>13.50</u>

a/A few of the large mines in the East could exceed this figure.

The timespans for the West relate primarily to environmental and other governmental considerations, which can account for a considerable portion of the time required, as shown in table 6.

Table 6

Time Needed for Environmental and
Governmental Actions (note a)

	<u>Minimum</u>		<u>Maximum</u>	
	<u>Years</u>	<u>Percentage of total</u>	<u>Years</u>	<u>Percentage of total</u>
Underground	1.5	50	6.0	44
Surface	2.5	63	7.5	50

a/Steps designated with (*) in table 5.

Accordingly, environmental considerations and governmental actions could be a major factor in the time required for opening of a mine.

INDUSTRY REQUIREMENTS TO
MEET EXPANDED PRODUCTION

If the bituminous coal industry is to produce the coal supply levels projected by the two scenarios, it will have to open new mines, recruit and train miners, improve health and safety conditions, purchase needed equipment, and secure the needed capital to accomplish the above tasks to a greater degree than ever experienced in the years prior to 1975. The following are the production level projections of the scenarios for 1985 and 2000.

	<u>1975</u> (actual)	<u>1985</u>	<u>2000</u>
	----- (million tons) -----		
Edison Electric Institute	648	779	942
BOM	648	988	1,587

The above figures compare with the 1985 goals of President Carter's National Energy Plan of 1.2 billion tons and 1 billion tons with and without the plan respectively. Our analysis of the various requirements shown above and the actions being taken or scheduled for future implementation is described in the following sections.

Industry expansion capability

A viable industry structure is needed if new mines are to be opened and operated to meet the production requirements projected by the scenarios. An indication of the industry expansion potential is the extent to which it is actively planning for the future and taking some of the preliminary steps necessary towards achieving those goals.

In performing our analysis, we reviewed coal production statistics; held discussions with coal operators and their associations, labor union representatives, and academic experts; and reviewed several reports based on questionnaires sent to operators, which showed planned mine openings.

Bituminous coal production in 1900 was over 212 million tons, all from underground mining. By 1910, it had almost doubled to about 417 million tons, all from underground mines. By 1920, it had increased to over 568 million tons, with about 8 million tons from surface mines and the balance from underground mines. There have been constant fluctuations in production since 1920, and in 1947 it reached a level of 631 million tons. From 1947 until 1961, there was a downward trend but from 1961 to the present there has been a steady upward trend. In addition, surface mining has increased, until it now exceeds underground mining.

Table 7 shows some of the more important 20th century production data, that is the high and low production years in each decade. 27/

Table 7

Important Coal Production Data

<u>Key years</u>	<u>Production</u> (million tons)	<u>Persons employed</u>	<u>Percent of total production</u>	
			<u>Surface</u>	<u>Underground</u>
1920	568.7	639,547	1.5	98.5
1926	573.4	593,647	3.0	97.0
1932	309.7	406,380	6.3	93.7
1937	445.5	491,864	7.1	92.7
1942	582.7	461,991	11.5	88.5
1947	630.6	419,182	22.1	77.9
1954	391.7	227,397	26.2	73.8
1956	500.9	228,163	27.0	73.0
1961	403.0	150,474	32.3	67.7
1969	560.5	124,532	38.1	61.9
1970	602.9	140,140	43.8	56.2
1974	603.4	166,701	54.0	46.0
1975	648.4	189,880	54.9	45.1
1976 (note a)	665.0	208,000	55.4	44.5

a/Estimated figures for 1976.

We projected the future production levels by coal-producing regions and type of mining--surface or underground. Table 8 shows the anticipated coal production requirements for each of the scenarios. 28/

Table 8

Future Coal Production Scenarios

	<u>1974</u> (actual)	<u>1985</u>		<u>2000</u>	
		<u>EEI</u>	<u>BOM</u>	<u>EEI</u>	<u>BOM</u>
	----- (million tons) -----				
<u>Eastern</u>	377.7	337.6	428.0	407.9	687.6
Underground	212.3	211.1	295.4	281.6	474.7
Surface	165.4	126.5	132.6	126.3	212.9
<u>Central</u>	142.5	147.8	161.4	153.6	257.5
Underground	54.8	64.8	72.6	69.2	116.1
Surface	87.7	83.0	88.8	84.4	141.4
<u>Western</u>	83.2	293.8	398.6	380.5	641.3
Underground	10.2	26.5	41.7	39.8	67.0
Surface	73.0	267.3	356.9	340.7	574.3
<u>Total</u>					
<u>United States</u>	603.4	779.2	988.0	941.9	1,586.4
Underground	326.1	302.4	409.7	390.5	657.8
Surface	277.3	476.8	578.3	551.4	928.6
<hr/>					
New mines opening (1975 to 1985)	-	152	254	-	-
New mines opening (1986 to 2000)	-	-	-	286	571

Opening of new mines

A survey conducted for the Federal Energy Administration identified planned and projected mine openings by 1985. Information was collected directly from coal producers--existing and potential--for over 300 planned and possible coal mine developments. The survey took into consideration 1974 production of 603 million tons, retirement of mines producing an estimated 137 million tons, and planned and possible new mine openings which could produce 546 million tons annually (the possible openings amounting to 135 million tons). The survey concluded that over 1 billion tons could be produced in 1985. 29/

This potential capacity is in excess of the requirements shown in the high scenario for 1985, and is in the same range as the National Energy Plan. It should be noted that the survey projected that the small mines--200,000 tons or less--would continue to produce at a level of 140 to 160 million tons annually. 30/

Our discussion with 11 major coal producers (including 9 of the top 15 producers in 1975) showed that all believed the industry could double production by 1985 and triple production by 2000, assuming certain conditions. Since 648 million tons were produced in 1975, a tripling of this production level would be well beyond the 1.586 billion tons required under the high projection for the year 2000.

GAO believes that there are serious obstacles which could delay achievement of a level of 1 billion tons to beyond 1985. These obstacles include such factors as long leadtimes to open mines, environmental restrictions, capital problems, and labor and productivity problems. On the other hand, a production level of 1.5 billion tons by the year 2000 could be achievable. At that point the constraining factors would be related primarily to demand.

Personnel

The increased automation of coal mining, the agreements reached in the National Bituminous Coal Wage Agreement of 1974, and the requirements of the Federal Coal Mine Health and Safety Act of 1969 have all had great effects on the mining work force. The once labor intensive coal industry has, over the years, shifted towards heavy reliance on equipment and a highly skilled work force well versed in equipment operation and repair. This applies to both underground and surface mining. 31/

We estimate that to continue to increase annual production to the various tonnages projected by BOM and EEI for 1985, between 93,100 and 157,000 new employees would have to enter the work force, with the average number of employees in 1985 being between 185,500 and 243,500. Similarly, to achieve the tonnages projected for 2000, from 195,200 to 374,600 additional employees will have to enter the work force and the average number of workers in 2000 will be from 232,000 to 390,600.

Our estimates of employee requirements, shown in table 9, are based on State productivity level statistics for 1974. These productivity figures are used to compute the employee requirements for the production levels forecast for 1985 and 2000. 32/

Table 9

Future Personnel Requirements

	<u>1974</u> (actual)	<u>1985</u>		<u>2000</u>	
		<u>EEI</u>	<u>BOM</u>	<u>EEI</u>	<u>BOM</u>
<u>Eastern</u>	134,296	131,000	176,100	167,900	282,900
Underground	101,773	103,900	147,700	140,800	237,300
Surface	32,523	27,100	28,400	27,100	45,600
<u>Central</u>	25,246	30,700	33,700	32,200	53,800
Underground	14,057	18,400	20,600	19,700	33,000
Surface	11,189	12,300	13,100	12,500	20,800
<u>Western</u>	7,159	23,800	33,600	32,000	53,900
Underground	3,586	11,100	16,500	15,700	26,500
Surface	3,573	12,700	17,100	16,300	27,400
<u>Total U.S.</u>	166,701	185,500	a/243,500	232,100	390,600
Underground	119,416	133,400	a/184,900	176,200	296,800
Surface	47,285	52,100	58,600	55,900	93,800
Entrants					
(1976-1985)	-	93,100	157,000	-	-
(1986-2000)	-	-	-	195,200	374,600

a/Differences due to rounding

The projections assume that productivity will remain constant; that is, gains in productivity will be offset by other factors requiring additional personnel. In addition, the number of new miners include replacements necessary due to retirements, deaths, and other reasons for leaving. 33/

To evaluate the capability of the coal industry to meet these goals and the potential implications, we examined the following matters.

- Availability of new miners for the coal industry,
- Industry ability to attract people to sparsely populated areas, such as in the West,
- Training requirements,
- Mine productivity,
- Effect of labor-management disagreements,
- Current and future effect of mine health and safety regulations.

Personnel availability

Because of the type of work and the health and safety hazards, the conjecture is that there might not be sufficient applicants to satisfy underground mining requirements. 34/ Also, there is some concern whether both new and experienced miners will move to those areas where new mines are being opened.

Underground miners--In recent years, risks and hardships of the underground miner's life have been partially offset by pay scales higher than in any other major industrial occupation. 35/ In December 1975, the underground bituminous coal miner earned an average wage of \$7.70 hourly, against \$6.42 for metal mining, \$6.89 for motor vehicles and equipment, \$3.55 for textile mills, and an average of \$5.00 for all manufacturing. 36/ We assume that this favorable relationship will be maintained and that coal price levels will continue to permit the operator to recover labor costs.

The underground mine operators we interviewed did not believe there would be a problem in securing new applicants. These views were supported by various studies on coal's future which conclude that, although the hazards are great, they will be offset substantially by other factors, such as improved safety conditions, unemployment trends, compensation

differential, and fringe benefits. Accordingly, the studies predict that there will be sufficient applicants for the potential openings. The United Mine Workers of America (UMWA), in the 1974 agreement with the operators, negotiated for increases in underground workers by the assignment of a helper to crews. It has been estimated that 7,500 more workers were classified as helpers in mid-1975 compared with 1974. 37/ These helpers should eventually be able to fill higher skilled jobs.

In an effort to reduce the serious sickness and accident record associated with the mining of coal, the Congress enacted the Federal Coal Mine Health and Safety Act in December 1969. As a result of the actions taken in accordance with the act, the Secretary of the Interior, reported, in his 1974 Annual Report, that improvements have been made in the working conditions of mines. Although mining is still a hazardous occupation, progress has been made. Since 1970 the fatality rate has been reduced by more than 50 percent and the non-fatal injury rate by 35 percent.

Recent increases in mine employment further indicate that there will be applicants. The average work force for miners in 1974 of 166,700 (of which 119,400 were working underground) increased in 1975 to 189,880 (of which 134,700 worked underground). 38/ This is an increase of 23,180 employees overall, including 15,300 underground employees, a 13 percent increase over the 1974 underground work force. Preliminary 1976 figures show an increase to 208,000 miners. 39/ In addition, during 1976 there were over 450,000 unemployed individuals in the coal mining regions who could provide a labor base for future expansion.

Flexibility of work force--The UMWA pointed out that while the increased demand for coal has brought economic gains to the miners, increased buying power has not solved a chronic problem for coal miners--housing. In fact, expansion of coal mining to meet the new demand is aggravating the problem. 40/ To the degree that housing and other requirements--schools, hospitals, entertainment, and shopping--are a problem in existing coalfields, they will be more severe in those rural areas where new coal mines are being developed, such as in the Northern Great Plains.

To retain experienced miners from closed mines and attract new miners from the labor market, efforts will be needed by industry, and local, State, and Federal governments to provide the needed infrastructure. These matters are discussed more fully in chapter 7.

Mining engineers--During 1973 and 1974 there were shortages of mining engineers, and it was necessary to hire engineers from other countries. 41/ However, in 1976, BOM reported that increased enrollment in the Nation's mining and mineral universities is evidence of an "encouraging reversal" of a downward trend. Total student enrollment in mining-related programs is currently 3,638, an increase of 668, or 22 percent, over the 1974-75 academic year. In the mining engineering area, the enrollment is 2,325, an increase of 544, or 31 percent, over last year.

Table 10 presents a comparison of student enrollment and graduation for the 1974-75 and 1975-76 academic years. 42/

Table 10

Student Enrollment and Graduation Levels

	<u>Enrollment</u>		<u>Degrees</u>	
	<u>1974-75</u>	<u>1975-76</u>	<u>1974-75</u>	<u>1975-76</u>
Mining engineering	1,781	2,325	360	459
Metallurgical and mineral processing engineering	1,052	1,176	258	325
Mineral economics	<u>137</u>	<u>137</u>	<u>43</u>	<u>43</u>
Total	<u>2,970</u>	<u>3,638</u>	<u>661</u>	<u>827</u>

According to an FEA-commissioned study in 1975, the number of engineers in bituminous coal and lignite mining would have to increase from 1,600 in 1974 to 3,000 in 1985. 43/ The numbers of enrollees and graduates appear to be within the range of satisfying these requirements.

Officials at three schools of mining that we visited did not believe that there would be any shortages of engineers in the future. In addition, the Secretary of the Interior on November 3, 1975, in reply to the Senate Committee on Interior and Insular Affairs, stated there is a strong interest in mining research and education. He pointed out that the Energy Research and Development Administration, the National Science Foundation, and BOM all provided funding to universities through grants and contracts to support various mineral and energy research projects. Private industry is also supporting mining education and training by providing endowments to colleges for purposes of scholarships and student loan funds, as well as faculty positions. He concluded that the growing need for mining expertise could be met through increasing

salaries and dissemination of information on the desirability of mining engineering careers. 44/

Miners--Figures in the revised UMWA pension plan, which went into effect in 1976, suggest that of a total of 131,375 active member miners as of October 17, 1974, 18,172 or about 14 percent, would be eligible for retirement. In some mines, it is possible that one-third of the work force would be eligible for retirement. 45/ In addition to the replacement of retired miners, the projected increase in coal production will require the recruitment of many new miners.

The trend in employment has been towards replacement of older miners with younger individuals which should result in a work force predominantly between 18 to 35 years of age. Table 11 shows an age comparison of active mine workers covered by the UMWA Health and Welfare Fund. The UMWA includes a major portion of the coal industry work force, over 80 percent. 46/

Table 11

Age Distribution of Active Miners in UMWA

(As of December 31)						
<u>Age group</u>	<u>1973</u>		<u>1974</u>		<u>1975</u>	
	<u>Number</u>	<u>% of total</u>	<u>Number</u>	<u>% of total</u>	<u>Number</u>	<u>% of total</u>
18-24	18,533	15.3	23,596	17.5	30,011	19.0
25-34	32,560	26.8	39,214	29.1	49,933	31.6
Subtotal	51,093	42.1	62,810	46.6	79,944	50.6
35-44	23,131	19.1	24,871	18.4	29,151	18.5
45-54	28,748	23.7	29,548	21.9	29,981	19.0
55-64	17,514	14.4	16,874	12.5	17,900	11.3
65 & over	862	.7	852	.6	974	.6
Total	121,348	100.0	134,955	100.0	157,950	100.0

The current shift from older to younger miners might cause a shortage of foremen and other middle management personnel. This problem could be temporary because the continued influx of miners should provide the base for new managers. There is some question as to whether there is a shortage of possible candidates for the positions, or simply a problem in training available candidates. 47/

The complexity of the work in coal mines as well as the health and safety precautionary measures to be taken require

that each employee be technically qualified to perform each task. Because of the specialized nature of the qualifications, actions must be taken to assure that the required personnel are properly trained. 48/

The leaders of both industry and labor agree that training of the work force--both workers and supervisors--is necessary, and provisions for training are included in the 1974 union agreement. 49/ In addition to company and on-the-job training, the industry has cooperated with engineering colleges in developing mining-related programs. 50/

An August 27, 1975, FEA report, "Determination of Labor Management Requirements in the Bituminous Coal Industry to Meet the Goals of Project Independence," summarized training as follows. 51/

"Our review of training activities in the coal industry indicates that (1) the National Bituminous Coal Wage Agreement of 1974 has a number of provisions affecting training activities directly and indirectly; (2) a large proportion of mine training is accomplished on-the-job by foremen or fellow workers; (3) a significant number of pre-employment training programs for coal miners are developing or are underway; (4) the construction industry, especially the Coal Construction Industry, and coal mining equipment manufacturer (sic) are providing much of the skilled maintenance manpower, and therefore the training, for surface mining; (5) training of foremen is primarily on-the-job and foremen are usually selected from the ranks of workers; and (6) public education facilities contribute greatly to coal miner training, especially in the training of maintenance personnel and professional personnel."

Management/union training agreement--The National Bituminous Coal Wage Agreement of 1974 has the following provisions that directly affect training. 52/

- The establishment of a joint industry training committee which consists of three representatives appointed by the union and three by the industry. The committee is charged with fostering and promoting the advancement of effective training in the industry.

--The requirement of 4-day orientation programs emphasizing health and safety for new inexperienced employees. State and Federal pre-employment programs are recognized, to the degree that they cover the program required by the contract. In most cases, the 4 days of orientation are a part of the company training program.

--The requirement for retraining programs emphasizing health and safety, which would require 8 hours for each employee in each calendar year.

--The requirement that no new inexperienced employee shall, for 90 days, operate any mining machines at the face or shall operate any transportation, mobile, or high voltage electrical equipment.

The agreement also provides for a 120-day period of on-the-job training for a helper-trainee continuous mining machine operator or roof bolter to become fully qualified for the position. Further, the employer has to provide training for maintenance jobs. The time set for training in maintenance positions in underground mines is 6 months for a trainee to progress to the minimum level of competence and an additional 21 months to progress to the highest rated maintenance job.

The agreement provides that in addition to orientation, miners will have on-the-job training and training of various kinds on a periodic basis.

Institutional training--In most areas of coal production, especially in underground mining areas, there are courses in coal mining or mine-related subjects available through local educational institutions such as vocational schools, secondary schools, community colleges, and, in a few cases, universities. 53/ A recent BOM tabulation showed the following number of institutions offering courses in mining and related subjects. 54/

	<u>Number of institutions</u>
Junior colleges and technical schools	40
Vocational schools	30
Universities	22

The students in junior colleges and technical schools receive associate degrees in engineering and training in mining technology. The vocational schools are teaching

reclamation, mechanics, and other mining skills at both the high school and post-high school level.

These programs should provide the trained personnel to satisfy projected coal production needs. In relation to training of maintenance personnel, it is believed the most effective means for training is in cooperation with educational facilities combined with on-the-job training. 55/

Training of surface mining employees--There is not much emphasis in training for surface mining operations, since most of these employees are hired from the equipment manufacturing companies, equipment erection companies, or the construction industry. Training programs are primarily of the on-the-job variety. However, there is some classroom training for special skills. For example, electricians are given 90 hours of classroom and on-the-job training concerning the equipment. 56/

Health and safety training--MESA is required to promote health and safety education and training. In this connection, MESA conducts courses for industry instructors, who in turn instruct mining personnel. 57/ The extent of such training will be discussed later in the section on miner health and safety.

Miner productivity

In order to keep mining costs to a minimum and thereby assure that coal will increase or at least maintain its competitive status with other fuels, there is a need to improve the current rate of productivity, that is, tons produced per worker-day. In the past several years, the U.S. coal mining industry has experienced declining productivity.

Before 1975, the highest annual coal production was in 1947, when 630 million tons were produced with 419,182 workers producing 6.42 tons per worker-day. The year with lowest production after that date was 1954 when 392 million tons were produced and 227,397 personnel employed, producing 9.47 tons per worker-day. Productivity reached its peak in 1969 when an average 19.90 tons per worker-day were produced for all types of mining; 15.61 tons per worker-day was the underground rate. It has since declined each year; in 1975 the rate was 14.74 tons per worker-day overall and 9.54 tons per worker-day for underground operations. 58/

Table 12

Mining Productivity Per Worker-Day

<u>Year</u>	<u>Underground</u>	<u>Strip</u>	<u>Auger</u>	<u>Average</u>
----- (tons) -----				
1940	4.86	15.63		5.19
1950	5.75	15.66		6.77
1955	8.28	21.12	22.22	9.84
1961	11.41	25.00	30.61	13.87
1969	15.61	35.71	39.88	19.90
1970	13.76	35.96	34.26	18.84
1974	11.31	33.16	N/A	17.58
1975	9.54	26.69	N/A	14.74
1976 (note a)	8.50	26.00	N/A	13.50

a/1976 figures are estimated.

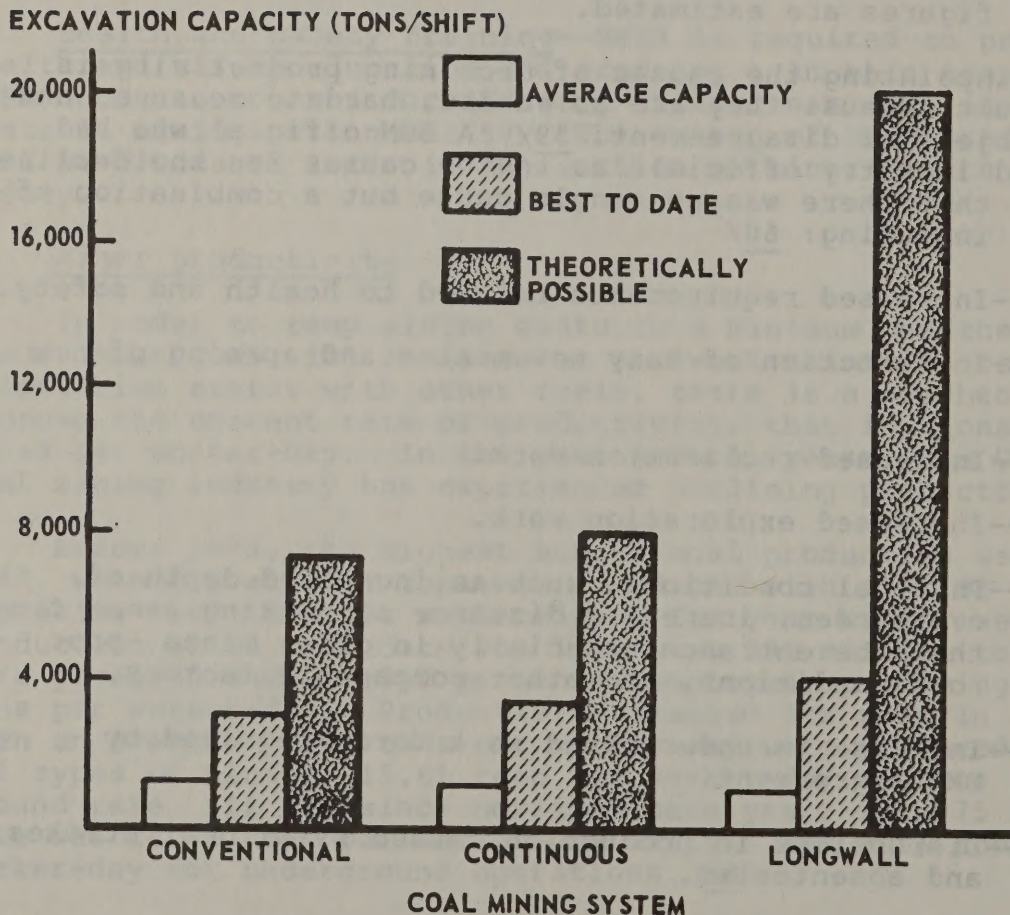
Pinpointing the causes of declining productivity is difficult because they are so varied, hard to measure, and the subject of disagreement. 59/ A BOM official who had queried industry officials as to the causes for the decline stated that there was no single cause but a combination of causes including: 60/

- Increased requirements related to health and safety.
- Introduction of many new miners and opening of new mines.
- Increased reclamation work.
- Increased exploration work.
- Physical conditions, such as increased depth of overburden, increased distance of working areas from the mine entrance especially in older mines, poor roof conditions, and other comparable factors.
- Increase in underground work force required by UMWA agreement.
- Disruptions in production caused by wildcat strikes and absenteeism.

Improvements in mining technology and increased employee motivation are considered the ways by which this downward trend can be reversed. 61/ BOM is directly concerned with improvements in technology. The Director, BOM, at the Third

Conference on Mine Productivity in April 1976, stated that the scientists and engineers in BOM believed that the three underground coal mining systems currently in use in this country have theoretical excavation capacities (tons/shift) that are not being used as shown in the following chart. 62/

CHART 1
RELATIVE EXCAVATION CAPACITY
BY COAL MINING SYSTEM



The Director also pointed out that although the theoretical limits may never be reached, it is possible to achieve considerable gains. He concluded that a substantial research and development program is essential if such improvements are to be realized.

Although the Director's address highlighted underground mining, BOM is also concerned with improving surface mining productivity. Considerable research and development efforts are being conducted on both underground and surface mining equipment and technology. 63/ (See page 4.52 for further details on existing and future projects to improve productivity.)

At the productivity conference, an industry representative said that there is a need to convince the miners that only a profitable company with favorable long-term prospects can consider long-term investments which will provide permanent, well-paying jobs. In addition, there is a need for the industry to assure that the grievance procedure is fair, effective, and prompt so that the air of confrontation and distrust is reduced. 63/

UMWA contends that unreachable productivity levels should not be set. It suggests that the companies hire and train substitutes to replace persons who are absent because of sickness or accidents, to avoid shutting down or just "making do." They concluded that, "Firms that try to be progressive in their policies, are fairly liberal, and operate safe mines, will have the best motivation among their employees." 65/

In conclusion, as noted by the BOM Director, if productivity levels were raised to the 1969 levels, coal production would be increased by 100 million tons annually without opening a single new mine. 66/

Management/union relations

The extent of interrupted production resulting from labor disagreements has been a matter of concern to the coal operators. During 1975 the coal industry lost approximately 1.6 million days due to unauthorized work stoppages.

UMWA represents about 80 percent of the production workers employed in the coal industry. Other coal-related unions are the Southern Labor Union, the Progressive Mine Workers, and, in the western coal lands, the International Union of Operating Engineers. 67/

Statistics maintained by the U.S. Department of Labor on strikes in the coal industry show an increased number of work stoppages in the past few years. Although the number of work stoppages has increased, the percentage of total working time lost is not substantial, except in years when a national agreement is renegotiated. For example, in 1973 less than 2 percent of total industry working time was lost in work stoppages. In 1974, however, 8 percent of the working time was lost. Table 13 shows the work stoppages and time lost during the last 10 years. 68/

Table 13
Statistics on Work Stoppages

	Workers involved (note a)				Days idle during year			Renegotiation of national agreements
	<u>Number of work stoppages</u>	<u>Number</u>	<u>Per stoppage</u>	<u>Percent of total employed</u>	<u>Number</u>	<u>Percent of total working time (note b)</u>	<u>Per worker involved</u>	
		(thousands)			(thousands)			
1966	160	88.1	551	67.9	629.0	1.9	7.1	x
1967	207	62.9	304	47.1	158.0	.5	2.5	-
1968	266	206.4	776	163.3	956.6	2.9	4.6	x
1969	457	206.0	451	159.1	900.6	2.7	4.4	-
1970	500	198.6	397	143.1	627.0	1.8	3.2	-
1971	606	350.7	579	261.1	4,215.1	12.4	12.0	x
1972	963	256.0	266	178.8	562.4	1.6	2.2	-
1973	1,039	290.2	279	183.7	556.8	1.4	1.9	-
1974	996	459.9	462	278.7	3,310.1	8.0	7.2	x
1975	1,139	387.2	340	195.4	1,501.3	3.9	3.0	-

a/Workers are counted more than once if involved in more than one stoppage during a year.

b/Idleness as a percent of estimated total working days is the ratio of days of idleness to average employment multiplied by total working days for the year.

Note: This data includes only stoppages lasting one full day or shift or longer and involving six workers or more. The number of stoppages and workers relate to those stoppages that began in a year; the days of idleness are derived from all stoppages in effect in a year.

Contract agreements--Over the years, union and management have negotiated increases to wages, better working conditions, procedures for handling grievances, and various fringe benefits. The agreement reached in 1974 includes the following. 69/

- Increases in wages and vacations, and adjustments to pay scales.
- Addition of helpers to certain work crews.
- Increases to pension fund payments by employers and greater benefits to retirees.
- Establishment of sick leave and sickness and accident benefits.
- Substantial revisions to job training requirements, including adoption of a requirement that new employees must spend their first 90 days in "nonhazardous" jobs.
- Granting union safety committees the right to inspect all work areas and the right for miners to withdraw from any area they consider unsafe.

It should be noted that the union failed to obtain the right to strike over local grievances, including safety matters. 70/

Current agreements of the UMWA and the Bituminous Coal Operators Association, Western Surface Miners, and National Coal Mine Construction Contractors expire December 6, 1977. The upcoming negotiations were the subject of the union's convention held from September 23 through October 2, 1976. 71/

The following are some of the demands agreed to at the 1976 UMWA convention in negotiating the 1977 agreement. 72/

- The "right to strike" provision had the greatest support. Local unions would have the option of solving a legitimate complaint through filing of a grievance or calling a strike. Therefore, the companies could be prevented from obtaining injunctions in these instances.
- The establishment of more efficient grievance procedures.

--All mines will have a full-time union safety committee-person properly trained who "shall have the power to shut down a jobsite, mine, or mine facility for health and safety reasons."

--Various safety demands, including the mandatory establishment of professionally trained mine rescue teams at all mines and a provision that no employee work alone.

--New health and retirement benefits and the provision of additional social services to western miners.

The election of national officers scheduled for November 1977 was moved up to June 1977 so there would be more time available for the president-elect and other incoming officers to prepare for the negotiations.73/

Role of the Government in coal industry dispute settlement--For purposes of determining whether striking miners can be discharged or otherwise disciplined, the National Labor Relations Board must determine whether the strike is a protected or unprotected activity. The operator cannot take adverse action when the circumstances show that the strike is a protected activity. There are four well-defined categories of protected strikes. 74/

--Strikes involving unfair labor practices.

--Strikes at the expiration of an agreement.

--Strikes over abnormally dangerous working conditions.

--Strikes over matters the contract leaves expressly to local settlement.

Unprotected strikes are those with an illegal purpose such as imposing a secondary boycott; those accompanied by illegal conduct, such as violence and intimidations at the picket line; also unprotected are strikes occurring during the life of a contract which contains a no-strike clause.

Section 301 of the National Labor Relations Act, provides that labor organizations that breach a labor-management agreement are subject to lawsuits for damages. Using this provision, the National Labor Relations Board has ruled that since the national coal agreement has a mandatory grievance procedure, it is equivalent to a no-strike clause. Striking in the face of such a mandatory procedure is a breach of contract and the Board considers the strike to be unprotected.

Although the Board has reached this conclusion, the courts have been anything but consistent in deciding whether the miners' contract has an implied no-strike clause. 75/

The companies take the view that only a small percentage of the strike situations in the organized sector of the coal industry are protected strikes and have filed over \$400 million in lawsuits against the union for allegedly illegal strikes.

The companies' primary concern is getting the miners back to work. Accordingly, they apply for cease and desist orders from the Board. However, if a strike is not proved to be a refusal to bargain, the Board cannot find it to be an unfair labor practice and cannot issue a cease and desist order. On the other hand, the courts have eased the way for companies to win court injunctions for violations of section 301. 76/

The Board will decline to settle charges of unfair labor practices where there is an arbitration procedure established by a labor-management agreement. 77/ Such an agreement is in existence in the coal industry and was established by the 1974 agreement. A tripartite (independent arbitrator-industry-union) Arbitration Review Board is the final step in the grievance procedure. It was instituted to resolve conflicting decisions by different panel arbitrators and to insure uniform interpretations of the contract. The main complaint by the union against the Arbitration Review Board is that it has acted too slowly. 78/

The rule followed by the Labor Relations Board is that it will not review a charge where "the proceedings have been fair and regular, all parties had agreed to be bound, and the decision of the arbitration panel is not clearly repugnant to the purpose and policies of the Act". [Spielburg Manufacturing Company, 112 NLRB 1080, 36 LRRM 1152 (1955)] 79/

In GAO's evaluation of the National Energy Plan, we recognized the seriousness of the impacts that management/labor disputes could have on a large, stable supply of coal and recommended that Congress expand the plan for coal to deal with the need for improved labor relations to prevent disruptions due to wildcat strikes.

Miner health and safety

In an effort to reduce deaths, disabling injuries, and disease incurred in coal mining, the Congress, in December 1969, enacted the Federal Coal Mine Health and Safety Act (30 U.S.C. 801).

The act prescribed interim mandatory health and safety standards applicable to all underground coal mines until the Secretary of the Interior promulgated standards. Health standards and safety standards for underground mines were published in the Code of Federal Regulations (30 C.F.R. Parts 70 and 75) and became effective in June 1970 and November 1970, respectively. Health and safety standards for surface mines were published in 30 C.F.R. Parts 71 and 77 in March 1972 and May 1971, respectively.

The act and the regulations prescribe health standards for controlling respirable coal dust which is the cause of pneumoconiosis, known as black lung. Health standards are also prescribed for dust resulting from drilling in rock, for respirable dust when quartz is present, and for noise. Miners are offered the opportunity to have periodic chest X-rays for the detection of black lung.

The major safety provisions of the act and the regulations relate to roof control, ventilation, and electrical systems and equipment. Safety requirements are established also for (1) combustible materials and rock dusting, (2) blasting and explosives, (3) equipment for transporting miners, (4) emergency shelters, (5) communications, and (6) fire protection.

Mine operators must adopt a suitable roof control plan, approved by MESA, for each underground mine. The regulations give the criteria to be followed by district office managers in approving the plans. Roof falls are one of the principal causes of fatalities in underground coal mining and approved roof control plans must be reviewed by MESA every 6 months. For calendar years 1974 and 1975, mine operators reported to MESA that fatalities from this cause numbered 49 and 47, respectively, or about 50 percent of all underground fatalities. 80/

To minimize the danger of explosions and electrocutions, the electrical system and equipment must meet specifications established by the Secretary of the Interior. These specifications are to be applied uniformly to all mines. The act also prescribes a program of coal mine inspections by MESA which is to consist of complete safety and health inspections of each underground mine at least four times a year and special spot inspections once every 5 working days of all mines having certain hazardous conditions. MESA has administratively determined that special spot inspections should also be made every 10 working days of certain other hazardous mines. In addition, the act requires that representatives of the mine operators make certain health and safety examinations.

The act also provides for expanded and upgraded health and safety education and training activities and technical assistance to mine operators. It further provides for a program of research and technical support aimed at making coal mining a healthier and safer occupation. Seven years have elapsed since the passage of the act and some progress has been made in health and safety, but many problems remain.

The respirable dust standard of 2.0 milligrams per cubic meter of air became effective on December 30, 1972. It was established to prevent new miners from contracting black lung and to prevent further progression of the disease in miners who had already gotten it. 81/

MESA was established in 1973 to carry out the provisions of the act. Before 1973 these responsibilities were carried out by BOM. 82/ Among its functions is conducting inspections related to compliance with the dust standards. Dust samples taken by operators and by MESA in the 4,414 mine sections that were active for some portions of 1975 showed that 1,374 (31 percent) exceeded the standard at least once during 1975 and 3,040 (69 percent) were in compliance with the standard every time they were sampled.

Although reaching this level of compliance with the dust standards is an improvement over previous dust levels, full compliance with dust standards is considered essential. There are compelling human and economic reasons for eliminating pneumoconiosis. The human pain and suffering is obvious. In addition, monthly benefit payments for those who have black lung were over \$73 million in June 1975 and total benefits paid through June 1975 were over \$3.6 billion. 83/

Table 14 shows the fatality statistics since 1969. The number and frequency of fatal injuries in bituminous coal mining dropped steadily from 255 deaths in 1970 to 131 in 1973. The number of deaths was 130 in 1974 but increased to 152 in 1975. The frequency rate, deaths per million worker-hours, remained unchanged because of increased employment in 1975. During the 11-month period ended November 1976, there were 125 deaths which included the 25 men killed in the Scotia disaster. 84/

Table 14

Fatalities in Bituminous Coal Mines

	Underground mines		Surface mines	Preparation plants	Total	Rate	
	Underground	Surface				Per million staff-hours	Per million tons
1969	149	14	31	9	203	.85	.36
1970	205	14	31	5	255	1.02	.43
1971	140	8	24	4	176	.73	.32
1972	121	5	19	8	153	.53	.26
1973	98	8	17	8	131	.45	.22
1974	89	7	26	8	130	.42	.22
1975	98	a/12	34	8	152	.41	.24
1976 (note b)	95	a/ 5	20	5	125	.35	.20

a/Includes two off-mine property deaths.

b/Data available for 11 months only.

A comparison of fatality rates per million worker-hours for the various segments of mining, table 15, showed that although underground operations were the highest, surface fatality rates could not be considered low. 85/

Table 15

Fatality Rate in Bituminous Coal Industry
Per Million Worker-hours

	<u>Underground mines</u>		<u>Surface mines</u>		<u>Preparation plant</u>	<u>Overall rate</u>
	<u>Underground</u>	<u>Other</u>	<u>Strip</u>	<u>Other</u>		
1969	.98	.72	a/.64		.50	.85
1970	1.26	.75	a/.59		.31	1.02
1971	.91	.45	a/.43		.25	.73
1972	.64	.23	a/.33		.43	.53
1973	.51	.36	a/.30		.42	.45
1974	.44	.28	.40	.57	.43	.42
1975	.39	.33	.49	.81	.36	.41
1976	.41	.13	.27	.00	.18	.35

(note b)

a/Strip and auger combined.

b/Data available for 11 months only.

In terms of fatalities per million tons, underground rates would be higher because of the lower productivity per worker-hour of underground mining.

An accident prevention program was initiated by MESA in 1973 to decrease the number of non-fatal injuries in coal mines by devising safer mining methods. Initially the program was directed to underground mines employing 200 miners or more which had a disabling frequency rate higher than the national average. This was expanded in 1975 to include mines employing 150 or more miners. 86/ Inspectors were assigned to these mines on a daily basis to review operations and coordinate with management and employees. MESA made 3,331 such inspections in 1974 and contends that the lower injury rate in 1974 is in part attributable to this program. 87/

The trend of disabling accident rates is shown in table 16. American National Standards Institute, Inc., defines disabling injury as a work injury which results in death,

permanent total disability, permanent partial disability or temporary total disability which results in the loss of at least one complete work shift. 88/

Table 16

Disabling Injuries in
Bituminous Coal Industry (note a)

	<u>Number of accidents</u>	<u>Rate per million work-hours</u>
1969 (note b)	10,120	42.61
1970 (note b)	11,812	45.40
1971	11,539	47.13
1972	12,165	46.55
1973	11,011	40.54
1974	8,429	28.90
1975	11,009	30.31
1976 (note c)	13,800	36.16

a/Includes fatalities.

b/Includes anthracite mine statistics.

c/Preliminary.

The rate of occurrence of disabling injuries has decreased by almost 25 percent since 1973. However, the absolute number of such injuries is still high.

Assuming that the fatality and disability injury rate does not improve greatly from the 1975 rate, we estimate that as many as 3,400 miners might be killed and 253,000 disabled in accidents under the EEI levels of production for the 25-year period ending 2000. For the BOM scenario, as many as 4,700 miners might be killed and 351,000 may be disabled.

Reducing the number of accidents and the resulting fatalities and disabling injuries is an important concern to all parties in coal production. MESA has been expanding inspections to assure compliance with the Federal Coal Mine Health and Safety Act and to detect areas which require corrective action. It believes that miners deserve and need more intensive training and has drafted regulations for mandatory training of miners. It is also considering establishing qualifications, certification, and licensing of certain mining and supervisory jobs. Efforts have been exerted in research and development for new equipment as well as improvements to existing equipment. The number of miner's lives that have been saved from roof falls by cabs and canopies installed on underground equipment has been

great, and 36 lives were reported saved in 1975 by these safety accessories. 89/

The coal industry is cooperating with MESA and considers safety and safety training very important. 90/ The industry is also cooperating in health and safety research and development projects. UMWA is vitally concerned with health and safety and many safety items are included in their demands for negotiating with the industry. UMWA contends that MESA training requirements should be expanded beyond what has been proposed. 91/

Equipment

As already noted the coal mining industry has become increasingly automated. This is especially true in surface mining where huge equipment is used to move large amounts of earth and rock (overburden) to get the coal. 92/

Equipment shortages during the 1974 surge in coal output raised questions as to the availability of equipment to meet future production needs. 93/ The questions to be resolved are how much new equipment will be needed to achieve the production goals established for the years 1985 and 2000 and will such equipment be available in time.

Requirements

Predictions of the type and quantity of equipment that will be needed to support given production levels are dependent upon several factors. Maximizing safety while minimizing costs are the key objectives in proper equipment selections. The equipment selected will depend upon: 94/

- Required rate of production to meet customers' needs.
- Depth and volume of overburden to be moved in surface mining, and the location and depth of the coal seam in underground mining.
- Characteristics of the overburden as they relate to removal problems in surface mines and roof support requirements in underground mines.
- Overburden segregation requirements required for proper reclamation in surface mining.
- Distance, route, and elevation from the bank to spoil pile or discard area for surface mines.

--Coal characteristics, such as quality and thickness of the seam and the extent of partings or intermittent layers of foreign matter.

--Coal haul distances and elevation changes.

The quantities of new equipment to be procured depend on the number of mines to be opened and the equipment in existing mines to be replaced by 1985 and the year 2000.

Using BOM projections of equipment needs to achieve 1.2 billion tons of coal production by 1985 as a baseline, ^{95/} we have estimated replacement and new installation requirements for 10 selected equipment items. These estimates are for the production levels cited in the EEI and BOM scenarios for 1975 to 1985 and 1986 to 2000. Table 17 summarizes these estimates.

Table 17

Estimated New Equipment Requirements

	<u>1974</u> <u>In use</u>	<u>1976</u> <u>EEI</u>	<u>to 1985</u> <u>BOM</u>	<u>1986 to 2000</u> <u>EEI</u>	<u>BOM</u>
Annual production (millions of tons)	603	779	988	942	1,586
<u>Underground items</u>					
Continuous miners	1,976	3,300	4,500	3,450	6,550
Longwall equipment	50	30	60	110	180
Cutting machines	1,600	800	800	600	800
Mobile loaders	1,800	800	800	650	850
Shuttle cars	6,500	5,500	6,800	5,400	9,100
Conveyors	3,985	6,550	8,500	5,900	11,000
Locomotives	3,095	550	550	650	880
Mine cars	43,330	7,700	7,700	9,250	12,300
<u>Surface items</u>					
Draglines (large)	a/100	180	250	150	310
Coal loading shovels	a/600	550	700	900	1,270

a/Estimates.

Availability

Timing of procurement is important since the most modern coal mining equipment is not mass produced. Common and standard mining equipment is delivered within a minimum amount of time, but larger, more sophisticated equipment will take longer. BOM indicated that some equipment can take from 6 months to 4 years to manufacture depending upon its complexity. Equipment delivery time further depends on the availability of raw materials and the manufacturer's productive capacity. 96/

During the 1974 surge in output, increased demands were placed on equipment manufacturers to furnish needed equipment. At the time, the equipment manufacturers were not prepared for the sudden flood of orders, which caused backlogs and extension of delivery times. Manufacturers of both surface mining and underground mining equipment had difficulty obtaining raw materials, particularly steel, to meet demands. The problem was most acute for the large draglines used for surface mining, where production time increased from 2 to 5 years. 97/ Recent studies performed by BOM and by a consulting firm for FEA have indicated that equipment availability would present no great problems, with the possible exception of the large draglines. 98/

We discussed this matter with coal producers and dragline manufacturers who told us that the extensive backlog situation has been overcome. Many of the orders received during the 1974 surge have been deferred by the coal producers. Equipment manufacturers' capacity is being expanded to meet expected coal demands, and production time has been reduced from 5 to 2-1/2 years. Consequently, if there is adequate planning by the coal mining industry in its ordering of equipment, the manufacturers should be able to produce and deliver the items. Dragline production continues to be a question, however.

BOM has observed that, although productive capacity of existing dragline producers has expanded, there might be short periods when backlogs in dragline deliveries might occur. One of the dragline manufacturers disputed this point, indicating that there would not be any shortage.

Backlogs could delay the opening of a surface mine and the commencement of coal production. However, there is other earthmoving equipment available which could be used as a stopgap measure, although it would be more costly.

Financial

Capital investment needed to expand future coal production will be substantial compared with current rates of investment in the industry. Based on recent BOM estimates of capital costs per annual ton of new production capacity, we estimate that capital requirements to achieve the scenario levels of coal production through expansion of old mines and opening of new mines may range as follows: 99/

Table 18

Cumulative Capital Requirements
1975 to 2000

	<u>EEI scenario</u>	<u>BOM scenario</u>
	(billions)	
1975 to 1985	\$ 9.0	\$15.7
1986 to 2000	<u>17.7</u>	<u>29.8</u>
Total	<u>\$26.7</u>	<u>\$45.5</u>

Other recent estimates of coal industry capital needs to achieve a production capacity of about 1 billion tons annually by 1985 follow:

<u>Estimating organization</u>	<u>Level of output</u>	<u>Capital requirement (note a)</u>
	(billions of tons)	(billions)
MITRE Corporation	1.1	\$ 9.8
Banker's Trust of New York	1.1	12.5
BOM	1.0	14.4
Continental Illinois Bank of Chicago	1.0	20.0
National Coal Association	1.2	18.2 to 22.1
FEA	1.04	17.7

a/All requirements are in 1975 constant dollars.

Total coal industry capital expenditures from 1965 to 1974 was \$6.5 billion, or an average of \$650 million per year; this indicates the need for an unprecedented rate of capital investment under both the BOM and EEI scenarios. 100/ Financial experts expect at least half of the industry's capital must be provided from external sources. 101/

As an illustration of the current cost of opening new mines, BOM has recently made the following estimates for mines with a capacity of 1 million tons per year. The costs are shown in table 19. 102/

Table 19

Capital Cost Per Annual Ton
of New Productive Capacity

	<u>Underground mines</u>	<u>Surface mines</u>
Initial investment	\$31	\$18
Deferred needs--over operating life of mine	<u>10</u>	<u>3</u>
Total	<u>\$41</u>	<u>\$21</u>

The BOM estimates mean that \$41 million would be needed to open and operate a 1 million ton per year underground mine. A surface mine of similar capacity would require \$21 million. These estimates reveal a sharply rising trend in capital requirements. Similar BOM estimates prepared in 1974 showed capital needs of from \$15.20 to \$31.37 and from \$16.65 to \$22.53 per annual ton of production, respectively, to open new underground and surface mines. 103/ Increased capital costs are attributable primarily to inflation in the cost of coal mining equipment, which has increased two to three times as much as that of the rest of the economy. 104/

Sufficiency of capital investment

The capital requirements of the coal mining industry, while large in comparison to past needs, constitute only a small portion of the total future capital needs of all energy industries, estimated by FEA at \$580 billion, to provide for the energy requirements in 1985. 105/

Future coal projects, such as new mine openings, will have to compete in the capital market for investment funds with other energy and nonenergy related projects. 106/

Possible impact of horizontal divestiture on coal industry capital acquisition

During early expansion years and through the industry stagnation in the 1960s, the coal industry traditionally financed new ventures from internal funds. More recently, the entry of major oil and other companies, such as railroads, into coal mining activities has made new sources of capital available. For example, oil companies, now control about 18 percent of U.S. coal reserves. Railroads control about 9 percent. ^{107/} These companies have provided the coal industry with sources of funds not previously available.

Financial experts told us that if Federal legislation requiring horizontal divestiture of coal interests by oil companies is adopted, the coal industry will lose an important source of capital. ^{108/} Horizontal divestiture is the subject of another review being conducted by GAO and the issue and its various implications will be addressed in a separate report.

The Federal loan guarantee program for new underground, low-sulfur coal mines

To encourage the development of new underground, low-sulfur coal mines, Title I, Section 102 of the Energy Policy and Conservation Act of 1976 (P.L. 94-163), provides for loan guarantees (not to exceed \$30 million each) totaling up to \$750 million. To date, no guarantees have been granted under these provisions, nor have implementing regulations been promulgated by FEA. FEA and banking officials observed that, if implementing regulations closely follow the provisions of the act with respect to the requirements for guarantees, relatively few guarantees would be granted, because eligibility criteria are no more lenient than the usual credit requirements of commercial banks. Those marginal projects that cannot be financed through commercial lending institutions--which the program is presumably intended to encourage--probably would not qualify for loan guarantees. ^{109/} In view of this history, we believe the Congress should consider the need to amend this section.

Tax considerations

Taxes can change economic decisions, especially where profit margins are small. Coal is produced generally by incorporated firms subject, for the most part, to the same Federal tax rate and provisions as other incorporated domestic concerns.

The investment tax credit

Coal firms, as well as other domestic firms, are permitted a tax credit equal to 10 percent of up to 100 percent of the purchase price of qualifying machinery and equipment. 110/ The purpose of this provision is to stimulate the acquisition of selected equipment which, in turn, will affect economic growth and employment. The amount of this credit, referred to as the investment tax credit, is subtracted from the firm's Federal tax liability. At the corporate tax rate of 48 percent the credit is worth almost twice the value of a usual business deduction because the corporate income tax rate decreases the after-tax value of the deduction to about half but the credit is already valued in after-tax terms. Hence, in after-tax terms, a \$10.00 deduction is worth only about \$5.00 but a credit of \$10.00 retains its worth of \$10.00.

The credit is, however, subject to a limitation; it generally cannot exceed 50 percent of tax liability after the first \$25,000 of tax liability (for which the sole limitation is that the credit cannot exceed tax liability). If a firm cannot use this credit in the year incurred, the firm can apply that credit against the Federal taxes of the previous 3 years and the ensuing 7 years. 111/

The limitation provision, therefore, tends to bias the effect of the credit so that it works efficiently only in more profitable firms. For purposes of this discussion, profit is considered to be similar to taxable income. An industry with high capitalization requirements (high investment requirements) and a small profit, such as has characterized the coal industry in the past, would not benefit as greatly as a similar industry with higher profits. Internal Revenue Service statistics show that the coal industry has generally qualified for more of these credits than it could use, thereby forcing firms to carry over such benefits to subsequent years. 112/

The depletion allowance

Industries are permitted a deduction for the depletion and exhaustion of natural resources, such as minerals or timber, in which they have an economic interest. 113/ This is similar in principle to the depreciation of equipment, in that it is the recovery of cost at the rate the mineral is produced. 114/ This ratable cost recovery is known as cost depletion. 115/

Coal producers are accorded an option to cost depletion; a percentage depletion deduction of 10 percent of gross income from mining, not to exceed 50 percent of the taxable income from each mine, calculated without regard to the depletion allowance. 116/ While this is not as high as the 22 percent previously allowed crude oil and natural gas producers, and still accorded sulfur, uranium, and many other domestic minerals, 117/ it is, in most instances greater than depletion based on cost. Percentage depletion ignores and can exceed the cost of property. The deduction for percentage depletion may be claimed so long as the property is producing. The deduction for cost depletion, however, is permitted only until the original cost of the property is recovered. 118/

The net income limitation for the coal depletion deduction allowance has the same effect that the limitation poses for the Investment Tax Credit. Marginal mines are precluded from realizing the full tax benefits that more profitable mines enjoy. In general terms, this means that it is possible to have a larger depletion deduction than the limitation allows. This can occur when profit (taxable income) is low relative to gross receipts. In other words, when it costs more money to operate a coal mine (relative to other businesses), the depletion limitation can impose an additional financial disincentive by postponing tax benefits to future years. In extreme cases, a firm can lose tax benefits entirely when the limitation period expires.

Depreciation allowance

Under the Internal Revenue Code, a firm may depreciate all of its depreciable mining assets over an 8- to 12-year period. It may also use accelerated methods, such as double declining balance and sum of the years digits. 119/ While these methods represent faster cost recovery, they provide no special benefit to coal since all other industries enjoy similar tax treatment of capital assets. 120/

Rapid amortization of coal mine safety equipment

There is a special provision allowed for coal mine safety equipment placed in service prior to January 1, 1976, in the Internal Revenue Code. 121/ The purpose of this provision is to give coal mine operators an incentive to purchase coal mine safety equipment. This provision permitted the

purchaser of qualified equipment the option of either depreciating this equipment the same way he would other equipment or amortizing it evenly over a shorter 60-month period. 122/ However, the rapid amortization election precluded the purchaser from using the Investment Tax Credit 123/ and with the recent increases to the credit, removed any incentive to use the rapid amortization as against using normal depreciation and the full investment tax credit allowance.

Capital gains treatment of coal royalty income

Owners of coal property (as well as owners of timber and iron ore properties) can treat royalty income as long-term capital gains. 124/ Capital gains tax treatment is considered preferential tax treatment since lower taxes are paid on such income. This benefit, while available to owners, is not available to producers--unless, of course, they own the coal property too, which is sometimes the case. 125/ The congressional intent here was to assist coal royalty owners, many of whom had entered into long-term contracts calling for royalties expressed in cents per ton which, of course, do not provide adjustments for price changes as do royalties expressed as a percentage of the value of the mineral produced. This contrasts sharply with other coal tax benefits which generally do not give preference to mineral ownership over production.

Nonpreferential treatment of coal exploration costs

A tax benefit accorded oil and gas but not accorded coal is the treatment of intangible drilling costs. These may be expensed or capitalized at the option of the taxpayer without repaying the tax benefit in the future. 126/ The counterpart for the coal industry is exploration costs which are also expensed or capitalized at the option of the taxpayer. But the coal exploration costs, if expensed, are "recaptured" when the mine begins to show a profit, that is, the coal producer repays the tax benefit accorded him earlier while the oil and gas producers do not. 127/

Legislative and regulatory constraints

There are particular measures which include obstacles to the rapid development of coal. These measures which have been enacted

--create uncertainties as to whether certain coal reserves can be mined or

--increase the costs of the coal.

Disincentives to coal production through taxation

In certain instances, the taxes imposed by a given State may serve as a disincentive to coal production in that State in a normal competitive economy. Some State taxes, such as severance taxes, increase coal production costs (and/or the sales price) while others such as income taxes reduce profits.

Eleven States accounted for over 90 percent of domestic coal production in 1973. ^{128/} We restricted our survey of State taxes to these 11 States. Usually States do not levy identical taxes; even if two States have similar taxes with identical rates (e.g., a sales tax of 4 percent), they impose that tax on different items. For example, Illinois imposes a sales tax on all purchases by manufacturing firms, ^{129/} while Ohio levies a sales tax on purchases by manufacturers but exempts machinery used directly in the manufacturing process. ^{130/} In Alabama, some items purchased by manufacturers are taxed at rates lower than the general sales tax rate. ^{131/}

Several States have categorized their taxes one way, (e.g., a sales tax) when they are more precisely something else (e.g., a gross receipts tax). For purposes of this discussion, taxes are categorized according to the nature of the tax.

Corporation income taxes--Most coal firms are taxed as businesses at corporate tax rates.

For the eleven States studied, the State corporation income tax rates are shown in table 20.

Table 20

State Income Tax Rate Comparison

	(Percent)	Corporate income <u>taxes</u>
Kentucky <u>132</u> /	4.0	up to \$25,000
	5.8	over \$25,000
West Virginia <u>133</u> /	6.0	
Pennsylvania <u>134</u> /	9.5	
Illinois <u>135</u> /	4.0	over \$ 1,000
Ohio <u>136</u> /	4.0	up to \$25,000
	8.0	over \$25,000
Virginia <u>137</u> /	6.0	
Indiana <u>138</u> /	3.0	
Alabama <u>139</u> /	5.0	
Wyoming <u>140</u> /	(a)	
Montana <u>141</u> /	6.75	
New Mexico <u>142</u> /	5.0	

a/Wyoming has no income tax.

While the definition of taxable income varies from State to State, it is generally similar to the definition of taxable income for Federal tax purposes. Pennsylvania also levies a 1 percent capital stock tax which is a levy on the actual value of the corporation as determined by net worth, or capitalized earnings and the market value of the shares. 143/ Corporate income taxes are generally levied on all types of firms regardless of the nature of their business. This form of tax generally produces a large proportion of the State's revenues. Since it primarily affects the companies' profits, it has little impact on the rate of production and on marginally productive mines. 144/

Sales taxes--Generally, the addition of a sales tax to an item has the effect of reducing the number of items that will be sold since they will be available at a higher price. For those States levying a sales tax, it generally provides about one-third of each State's revenues.

Sales taxes are imposed by almost all of the 11 States considered in this study; however, a substantial amount of coal production is usually exempted from the sales tax by these States. One-third of the States levy no sales tax on coal whatsoever and the remaining two-thirds exempt resources used

in the manufacturing process, interstate transactions, coal purchased for resale and/or coal used to produce energy.

Illinois is the only State studied which has a true sales tax (the Retailers Occupational Tax) affecting a significant amount of coal sold. Illinois has a State sales tax of 4 percent plus an additional 1 percent for the county, levied at the point of sale and stated explicitly in the terms of the sale. 145/ Indiana also has a 4 percent sales tax on coal sold at the retail level; however, exemption certificates for certain uses exclude substantial amounts of coal sales from the tax (e.g., coal sold for the production of energy). 146/

Production taxes--There are various types of taxes levied on the total production of coal firms. Prominent among them are severance taxes, gross receipts taxes, and ad valorem* taxes. This type of tax generally has a heavy impact on coal firms. In some cases, these taxes are levied exclusively on coal and not on other products.

West Virginia's gross receipts tax on coal is 3.85 percent of gross proceeds from the sale of coal. 147/ This tax produced more than \$100 million in revenues in 1975, over 14 percent of the State's total revenues in that year. This tax is credited against State income tax liability. 148/

Kentucky levies both a specific and an ad valorem severance tax, which amount to 50 cents per ton and 4.5 percent of gross value, respectively. The specific severance tax is merely a floor or alternative minimum tax to protect the State's revenue position. In 1975, with these taxes at 30 cents per ton and 4 percent, respectively, the State collected almost \$100 million, or about 8 percent of total revenues. 149/

Pennsylvania levies no production tax on coal and neither does Illinois nor Indiana. However, as mentioned previously, Illinois and Indiana do impose a sales tax on coal that is sold.

Ohio levies a specific severance tax of 4 cents per ton 150/ while Virginia authorizes a county tax of 1 percent of gross receipts. 151/ Alabama has a 13.5 cents per ton specific

*In proportion to the value.

severance tax on coal; 152/ Wyoming levies a 6 percent (effective 1978) ad valorem tax which, when combined with its so-called property tax on assessed value (value is determined by the price of the coal extracted) amounts to a 12 percent ad valorem tax. 153/

Montana has both a specific and an ad valorem severance tax. The specific severance tax, unlike Kentucky's, is tied to the wholesale price index but nevertheless acts as a floor or alternative minimum tax. For surface-mined bituminous coal, the ad valorem tax is levied at a 30 percent rate (at least 40 cents per ton) with an additional 0.5 percent for a resources indemnity tax. 154/ For deep-mined coal, Montana's taxes are 4 percent (at least 12 cents per ton) and 0.5 percent, respectively. 155/

New Mexico levies a gross receipts tax of 4 percent plus a 0.5 percent severance tax and a 0.75 percent resources excise tax. Local governments also levy about a 3 percent ad valorem tax on the adjusted gross value of the coal. 156/

Production taxes are variable costs and as such add to the costs of production. The economic impact of such taxes by a State, assuming a normal competitive industry, is to reduce the production of coal in that State. Specific severance taxes (and similar taxes) pose the additional problem of hastening the depletion of readily accessible and most profitable high grade reserves, relative to less accessible or low grade reserves. Although production taxes and sales taxes have been dealt with separately for purposes of this review, the economic effects of these taxes are similar.

Comparative analysis of alternative tax options

The evaluation of coal taxes is complicated by the fact that Federal and State governments may establish different and sometimes conflicting goals and objectives. The Federal Government's goals include national security, energy independence, the economic allocation of goods and services (or the neutrality of taxes among goods and services), and the raising of revenues to finance the Federal Government and its programs. The State's objectives include the maximization of revenues subject to the preservation of the State industry's competitive position, the mitigation of the socioeconomic costs of coal development, the general economic development of the State, and the economic neutrality between coal and all other energy resources.

High severance taxes, for example, may accomplish all of the State's goals, but such taxes, by increasing production costs, may reduce the production of coal and its consumption relative to other energy resources such as imported oil and gas. Compounding this problem is the fact that a tax credit is allowed on the Federal tax return for foreign taxes paid on imported oil and gas while only a deduction is permitted for State taxes paid for domestic coal production.

Other uncertainties

Taxation is not the only cause of uncertainty. The Government has established various policies relating to environmental considerations in an effort to reduce damage done by coal production and consumption to the air, water, and land. Although the need for such protection is recognized by the coal industry, they are critical of policies which, in their opinion, create uncertainty and are subject to revision. 157/

During the years of debate and compromise, the issues surrounding national surface mining legislation raised doubts as to whether coal could be mined as planned. 158/ Other examples are the need to file detailed mining plans to States and to prepare and file environmental assessments to the Department of the Interior which prepares the environmental impact statements for approval. 159/ In addition to delays, the operator is faced with the possibility that the permit will be denied or have conditions attached which would make it uneconomical to mine the coal and deliver it to the consumers based on the price negotiated.

The possibility of changes in air quality standards by the States and the Federal Government have also created uncertainties as to whether the coal planned to be mined would meet revised standards. 160/

Problems facing the Federal Government in establishing environmental and air quality standards are discussed in chapter 6.

Industry has also complained that recently enacted legislation on leasing of Federal coal lands does not permit long-range planning. 161/ Industry officials claim that the time limits for exploration and consolidation of leases into logical mining units (2 years) and for providing coal in commercial quantities (10 years) are unrealistic and too restrictive.

RESEARCH AND DEVELOPMENT TO INCREASE
PRODUCTIVITY AND TO FINANCE MINE
HEALTH AND SAFETY

A critical element affecting coal's ability to meet future energy needs is the development of technology to extract coal more efficiently and at acceptable economic and social costs. BOM's research and development activities are directed toward these goals, through three primary areas--advancing mining technology, mining health and safety, and environmental protection. Environmental research is discussed in chapter 6. Table 21 shows the estimated 5-year funding levels.

Table 21

Estimated 5-Year Budget for Coal
Extraction Technology Program (note a)

<u>Research segment</u>	<u>Fiscal year</u>							<u>Total</u>
	<u>1976</u>	<u>1977^b</u>	<u>1977</u>	<u>1978</u>	<u>1979</u>	<u>1980</u>	<u>1981</u>	
	----- (b) -----							
	----- (millions) -----							
Underground coal mining	\$45.8	\$11.4	\$47.0	\$ 60.5	\$ 63.7	\$ 62.7	\$ 59.5	\$350.6
Surface coal mining	9.3	2.3	11.7	13.7	15.5	15.0	14.7	82.2
Coal mine health	3.5	.9	4.1	4.6	4.2	3.6	2.8	23.7
Coal mine safety	<u>25.9</u>	<u>6.4</u>	<u>25.5</u>	<u>29.7</u>	<u>28.9</u>	<u>28.5</u>	<u>30.9</u>	<u>175.8</u>
Total	<u>\$84.5</u>	<u>\$21.0</u>	<u>\$88.3</u>	<u>\$108.5</u>	<u>\$112.3</u>	<u>\$109.8</u>	<u>\$107.9</u>	<u>\$632.3</u>

a/The figures presented in this table, obtained from BOM's draft report entitled Strategic and Tactical Plan, dated January 1976, are not precise but are indicative of possible allocations based on BOM management judgment at the time.

b/This is a transition period of 3 months (one-quarter year) from the previous fiscal year period beginning July 1 to the newly adopted fiscal year period beginning September 1.

This table indicates that the technology program funding peaks in 1979 with an estimated budget of \$112.3 million, a 33 percent increase over fiscal year 1976. The surface mining technology budget is \$15.5 million and represents a 67 percent increase over the fiscal year 1976 level. Underground mining also increases; however, the projected funding level is only a 39 percent increase over fiscal year 1976. The significant increase in surface mining technology research is more than likely a reflection of the relative importance surface mining will play in near term coal production. It should also be noted that the projected funding for health and safety research beginning in fiscal year 1978 is more than the current \$30 million limit. Exceeding the limit will require a change in the Coal Mine Health and Safety Act of 1969.

Advanced coal mining technology

BOM has identified certain bottlenecks to increasing coal mine productivity, such as installing roof supports; transporting coal, men, and supplies in underground mining operations; and reliability of continuous mining equipment. They are attempting to develop technology to overcome these obstacles and their aim is to develop and make improved mining technology available to industry as soon as possible. 162/

The objectives of the advanced mining research program are to improve present surface and underground mining and environmental practices, automate present systems (such as continuous mining and longwall mining), and develop and demonstrate new mining systems that substantially improve productivity. The program's emphasis is on improving underground mining techniques because the majority of coal reserves is at depths which make underground mining the only feasible long-term method of extraction.

BOM's underground mining research efforts are specifically directed to:

- Increasing the average production per shift.
- Accelerating the use of longwall mining.
- Developing mining systems to recover 80 percent of western coal deposits.
- Reducing the time required to open new mines.
- Developing technology to provide protection of surface environment from underground mining, such as subsidence and water contamination.
- Conducting feasibility studies of new mining systems.

BOM has estimated that some of the technology being developed will be available for commercial application in 1977.

Research into improving surface mining is also important because a significant portion of the projected coal requirements will come from such operations. The overall objective of surface mining research is to improve productivity along with health, safety, and environmental standards. BOM is conducting research on:

- Integrating excavation and reclamation systems to reduce environmental impact.
- Investigating mining techniques that represent alternatives to current surface mining techniques.
- Improving, through automation, the entire coal mining cycle.
- Developing reclamation techniques for arid and semi-arid regions.

Equipment and methodology developed under the surface mining research program, like the dragline augmentation device and the winch pulled dozer blade, should be ready for industry use beginning in 1978.

Coal mine health and safety

Coal mining is the most hazardous occupation in the United States. ^{163/} The social and economic costs of coal mining reflected in the injuries, occupational illnesses, and deaths suffered by coal miners are high.

Increased production will necessitate increased numbers of miners, and based on historical correlation, could lead to increased fatalities and injuries if there are no health and safety improvements.

BOM has, since its inception in 1910, performed research and development to improve working conditions in the coal mines. The Federal Coal Mine Health and Safety Act of 1969, among other things, directed the expansion of research and development programs aimed at preventing coal mine accidents and diseases. Until 1969, BOM's research was an in-house effort. The 1969 act augmented this effort by including a contract and grant research program and authorized a total health and safety research program with funding of up to \$30

million per fiscal year. The act further required that research be done in a number of specific research areas, which include:

- Improved working conditions and practices in coal mines.
- Developing new or improved methods of recovering persons in coal mines after an accident.
- Developing methods of reducing concentrations of respirable dust in active working areas of coal mines.
- Developing new and improved underground equipment and other sources of power for such equipment which will provide greater safety.

In response to the research areas enumerated in the act, BOM's research program has addressed the major causes of injuries in coal mines--the hazards associated with electrical and mechanical equipment, fire and explosions from combustible gases and dust, and health problems associated with respirable coal dust generated during mining.

The specific objectives of BOM's research into coal mine health and safety are to:

- Develop means to reduce the amounts of respirable dust, carbon monoxide, and other noxious or toxic contaminants introduced or produced during mining operations.
- Develop means to reduce excessive noise introduced or produced during mining operations.
- Develop means for the removal, dilution, and protection against the remaining environmental contaminants, including excessive humidity and low and high temperatures.
- Develop means for elimination or reduction of fire and explosion; failure and outburst of roof, rib, face, and highwall surfaces; inundation; and electrical and machinery hazards.
- Develop more efficient and safer means for survival and rescue of miners and for miner recovery in event of disasters.
- Continually identify new health and safety problems and develop advanced mining systems and subsystems to eliminate these hazards. 164/

Some of the research efforts into health and safety have been implemented by the coal industry. Accomplishments are:

- Air curtain devices for protecting personnel from dust.
- Pneumatic drill mufflers to reduce noise.
- Water infusion of coal seams for dust control.
- Pumpable roof bolts for improved roof support.
- Improved lighting systems for mining machines.

SUMMARY

The scenarios of future energy demand used in this report forecast that annual coal production will reach a level of from 779 to 988 million tons by 1985 and from 942 to 1,586 million tons by the year 2000. The high scenario is in the approximate range of President Carter's National Energy Plan. Coal production in 1976 was 665 million tons.

The expected growth in the coal industry within the 1975 to 2000 period will require:

- Opening 438 to 825 new mines.
- Recruiting and training 288,300 to 531,600 new miners (current average employment is 208,000).
- Investing \$26.7 to \$45.5 billion in new capital.

The short-run production capacity of the industry is limited to what can be extracted through increased production (surge capacity) at existing mines. In other words, coal is usually demand-constrained in the long run and supply-constrained in the short run. In English, this means that on the supply side significant amounts of time and effort are required to open new mines. Given time, coal companies can produce the coal if the demand is there. When construction time, equipment acquisition, environmental and related studies, permits, and so on are taken into consideration, it takes

- 1.5 to 3 years to open a surface mine in the East,
- 4 to 15 years for a surface mine in the West,
- 2.5 to 5 years for an underground mine in the East, and
- 3 to 13.5 years for an underground mine in the West.

GAO discussions with 11 major coal producers (including 9 of the top 15 producers in 1975) showed all believed the industry could double production by 1985 and triple production by 2000, assuming certain conditions. GAO believes, on the other hand, that a number of factors, including long leadtimes required to open mines, environmental constraints, time problems in delivery of heavy equipment, capital problems, and labor and productivity problems will delay beyond 1985 the achievement of a production level of 1 billion tons, let alone the 1.2 billion tons reflected in the National Energy Plan. On the other hand, a level of 1.5 billion tons may be achievable by 2000 on the production side. By then the primary constraints will be on the demand side.

In addition to environmental restrictions discussed in chapter 6, several other key factors affect coal production. First is productivity, that is, the tons produced per worker-day. Productivity has declined since 1969, especially in underground mines. This can be attributed to:

- The 1969 Federal Coal Mines Health and Safety Act which increased the number of personnel in the mines.
- Changes in mining conditions such as widths of coal seams, distances from entrances of mines to the operation faces, and amount of overburden.
- Introduction of large numbers of inexperienced workers into the mines.
- Requirements for additional personnel in accordance with union agreements.
- Unscheduled interruption in production caused by wildcat strikes.

Concerning the last item, it should be noted that in years when a national agreement is renegotiated the lost working time due to work stoppages is substantial. For example, 8 percent of the total working time was lost in 1974 for this reason. Current agreements of the UMWA with the coal companies expire December 6, 1977. The right to strike over local grievances is a major bone of contention between labor and management.

The second factor is industry structure. In recent years, the coal industry has undergone significant change. Major steel, utility, chemical, and metal companies have accelerated their move toward coal self-sufficiency and, like the oil companies, are aggressively acquiring small coal companies and coal reserves. The trend is definitely toward

fewer but larger companies. These changes are thought to have improved the capital position of what was once a capital-starved industry.

The third factor is worker availability and training. Wages in the coal industry are higher than in many other industries and should attract new miners. The training of those new miners is a more significant problem. Industry and Federal Government efforts in this regard need to be more extensive.

Fourth is the availability of mining equipment. If there is adequate planning by the coal mining industry in its ordering of equipment, the manufacturers should be able to produce and deliver most of the machinery on time. However, it appears that delivery of large draglines, critical to big surface mining operations, could still be a problem.

GAO discussions with economists and experts in the coal mining and financial communities indicated a consensus that future coal projects should be able to receive financing as long as coal demand remained reasonably good.

Seven years have elapsed since the passage of the Federal Coal Mine Health and Safety Act and some progress has been made in mine health and safety records. But problems remain. More needs to be done to reduce nonfatal injuries and to achieve full compliance with the dust standards.

Statistically, mining remains more dangerous than other major industrial occupations. Assuming that the fatality and disability injury rates do not improve significantly from the 1975 rate, GAO estimates that as many as 3,400 miners might be killed and 253,000 disabled in accidents under the EEI scenario levels of production for the 1975 to 2000 period. Under the BOM scenario as many as 4,700 miners might be killed and 351,000 disabled.

The impact of taxes upon the coal industry is very uneven. Some taxes encourage increased production while others discourage it. Coal mining receives a tax break with a percentage depletion deduction of 10 percent of gross income, but the deduction must not exceed 50 percent of the taxable income. On the other hand, a tax benefit accorded oil and gas but not coal is the treatment of intangible drilling costs--these may be expensed or capitalized at the option of the taxpayer without repaying the tax benefit. In addition, a foreign tax credit is allowed on the Federal tax return for imported oil and gas while only a deduction is permitted for State taxes paid on domestic coal production.

These tax provisions put coal at a disadvantage compared with oil and gas.

State taxes on coal production vary widely. State taxes such as Montana's 30 percent tax on the market value of surface mined coal may accomplish State goals, but such taxes, by increasing production costs, may reduce the production of coal and its consumption relative to other energy resources such as imported oil and gas. On the other hand, State taxes are a means of internalizing into the price of coal external socioeconomic and environmental coal costs.

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- | | |
|---------|---|
| Eastern | - Alabama, Kentucky (eastern), Maryland, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia |
| Central | - Arkansas, Illinois, Indiana, Iowa, Kansas, Kentucky (western), Missouri, Oklahoma |
| Western | - Alaska, Arizona, Colorado, Montana, New Mexico, North Dakota, Texas, Utah, Washington, Wyoming. |
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CHAPTER 5

HOW CAN WE GET IT TO WHERE WE WANT IT?

An effective and efficient transportation system is essential to permit coal to play a major role in meeting the Nation's future energy needs. While production capabilities must be greatly expanded to meet the future demands of utility and industrial consumers, the development of adequate transportation capabilities is equally important to insure that the increased coal output will be moved from mine to user. Scenarios forecasting production increases from the 1976 level of 665 million tons to as much as 988 million tons in 1985 and 1.586 billion tons in the year 2000 also entail a need to expand transportation system capabilities accordingly.

The existing system, comprised primarily of railroad, barge, and truck transport, has demonstrated its ability to move the current level of coal output and to handle temporary demand surges, as was demonstrated during and after the oil embargo. But, increased output will, in some instances, place added burdens on currently marginal system capabilities which already require improvements. More importantly, however, potential increases in coal production, particularly in the West, will place new demands on the Nation's coal transportation system that must be met by building new facilities and expanding existing capabilities.

Future coal transportation requirements can be met, but Federal action may be needed. The railroads have the capability to expand, but expansion will not be without problems, particularly capital acquisition. Resolving uncertainties affecting future coal traffic volume would assist the railroads in planning and acquiring capital for expansion. The environmental impacts of increased rail coal traffic on certain communities en route may be severe. In the East and Midwest, Consolidated Rail Corporation's (Conrail's) rehabilitation efforts will need to include actions to insure that its coal-carrying capabilities are upgraded.

Coal slurry pipelines* are a possible option for moving coal in certain cases. Some significant environmental and institutional problems will need to be resolved. Development

*A pipeline which transports fine particles of coal suspended in a liquid carrier, such as water.

is being hindered by difficulty in assembling rights-of-way. Development could be additionally affected by shortage of water at the points of origin, particularly in the West, and by environmental problems caused by effluent disposal at the destination.

Expanding inland waterway capacity may also be necessary to substantially increase coal barge traffic.

The more important aspects of the total transportation issue are:

- Adequacy of the Nation's transportation system to move coal.

- Future coal transportation needs.

- Railroad expansion capability to handle future coal production.

- Future rail coal traffic.

- Railroad plans to meet 1980 coal transportation requirements.

- Ability of railroads to acquire the capital needed to finance expansion.

- Environmental impacts of rail coal traffic.

- Adequacy of Conrail's rail system and its ability to efficiently transport increased coal traffic.

- Adequacy of rolling stock to move anticipated future coal output.

- Role of coal slurry pipelines in the development of coal.

- Coal slurry pipelines and the Federal power of eminent domain.

- Adequacy of water for slurry pipeline use.

- Disposal of effluent from slurry pipelines.

- Capability of inland waterway system to meet future coal transportation needs.

ADEQUACY OF THE NATION'S TRANSPORTATION SYSTEM TO MOVE COAL

Coal moves from mine to user principally by rail, water, and truck. Tramways, conveyors, and pipelines each transport lesser quantities. As an alternative to moving coal itself, coal can be converted to electricity by generating plants near the mine and the energy transmitted by wire to consumers. When the technological and economic problems are solved, the same approach would be possible for synthetic gas converted from coal at the mine and transported to the user by pipeline.

Coal shipments by the various modes of transportation from 1973 through 1975 are shown in table 1. 1/ Railroads carried about 65 percent of the coal traffic in 1975, compared to about 69 percent in 1973.

Note: Numbered footnotes to ch. 5 are on pp. 5.32 to 5.37.

Table 1

1973-75 Coal Shipments

by Mode of Origination (note a)

<u>Mode of transportation</u>	<u>1973</u>	<u>1974</u>	<u>1975</u>
	----- (million tons) -----		
Rail	397.2	397.2	418.1
Water	68.6	67.8	69.1
Truck	57.3	66.4	79.4
Used at mine-mouth generating plants	64.4	66.6	73.5
Other (including slurry pipeline and miscellaneous use at mine)	<u>4.3</u>	<u>5.5</u>	<u>8.3</u>
Total output	<u>591.8</u>	<u>603.5</u>	<u>648.4</u>

a/This table shows shipments by originating modes only; inter-modal transfers, particularly between rail and water, increase the total coal traffic handled by these modes substantially. For example, total coal traffic moved by water in 1974 amounted to 141 million tons, including the tonnage originated by other modes, but delivered to users by barge. 2/

Transportation costs represent a major portion of the delivered price of coal. These costs range from approximately 25 percent of the cost of coal delivered from eastern coal fields to as much as 75 percent or more of the delivered price of coal shipped from Montana and Wyoming to electric utilities in the Midwestern States. 3/ From 1974 through 1976, rail transportation costs accounted for the following percentages of the delivered coal price. 4/

Table 2

Average Rail Transportation Share
of Delivered Coal Prices

<u>Year</u>	<u>Price per ton</u> <u>f.o.b. mine</u>	<u>Average</u> <u>rail charge</u>	<u>Delivered</u> <u>price per ton</u>	<u>Transportation</u> <u>share</u> (percent)
1974	\$15.75	\$4.71	\$20.46	23
1975	19.24	5.25	24.49	21
1976 (note a)	20.00	5.75	25.75	22

a/Estimated.

A sample of selected coal-using utilities, reported in an April 1975 MITRE Corporation study entitled "Analysis of Steam Coal Sales and Purchases," showed that transportation costs varied from \$0.47 a ton to \$10 a ton, depending on distance and mode of transport. 5/

Of the three currently most prevalent modes of coal transport, barge hauling ranks as the least costly, followed by rail and truck. 6/

Table 3

Comparative Modal Costs per Ton-Mile

<u>Mode of</u> <u>transportation</u>	<u>Approximate</u> <u>cost</u>
Barge	\$0.003 to \$0.004
Rail	.01
Truck	.05

A recent Bureau of Mines study of alternative electricity costs based on four western coal transportation alternatives indicated that slurry pipeline costs would be comparable to rail costs, but the cost of generating electricity near the mine and then shipping it by extra-high-voltage transmission lines was found to be about 30 percent higher. (See table 12, p. 5.25.) 7/

Future coal transportation needs

If future coal traffic by the various modes were projected in the same ratio as they were in 1975, the 1985 and the year 2000 BOM and Edison Electric Institute scenarios output levels would be allocated as shown in table 4. 8/

Table 4

Future Coal Transportation Shares

	1975 actual	Scenarios			
		1985		2000	
		EEI	BOM	EEI	BOM
----- (million tons) -----					
Rail	418	503	637	608	1,023
Water	69	83	106	101	170
Truck	79	95	120	115	193
Mine-mouth use	74	89	113	107	181
Other (including slurry pipelines)	<u>8</u>	<u>9</u>	<u>12</u>	<u>11</u>	<u>19</u>
Total output	<u>648</u>	<u>779</u>	<u>988</u>	<u>942</u>	<u>1,586</u>

If production increases, vast quantities of coal will have to be moved from areas served by transportation systems which, if not improved, could prove inadequate to the task. Western coal production, for example, may increase nearly fivefold by 1985 over 1974 levels and will require major improvements to existing western rail systems or supplementation with alternate modes of transportation such as slurry pipelines. Increased coal production will also place added demands on eastern rail systems and on the Nation's inland waterways.

EXPANSION OF RAILROAD CAPABILITIES

Railroads will be the principal mover of U.S. coal in the foreseeable future. The waterway system does not directly serve many of the areas scheduled for major coal development and is limited in its capability to expand by the present physical capacity of its locks system. There are also problems with ice in the winter. The trucking industry cannot compete with the railroads from a cost standpoint for high-volume, long-distance traffic. Large-scale generation of electricity near mines and long-distance transmission by extra-high-voltage lines over great distances is unlikely in the short term due to higher costs resulting from transmission losses* and may also be limited in some areas by regional shortages of water necessary for steam generation as well as public opposition because of environmental impacts. A proposed alternative to railroads for high-volume long-distance shipment--the coal slurry pipeline--is presently hindered by difficulties in obtaining rights-of-way and could prove infeasible due to shortages of water in originating regions, as well as the environmental and economic aspects of disposing of the effluent at the receiving end.

Production of coal-based synthetic high-Btu gas in large quantities is not anticipated in the near future. 9/ When synthetic high-Btu gas becomes economically producible, it is expected to be transported to the extent possible by the existing natural gas pipeline systems. 10/ If low-Btu gasification is used, a separate, larger capacity pipeline system would have to be installed.

The future of coal transportation through 1985, therefore hinges primarily on the railroads' capability to expand and improve their existing facilities, although the alternate modes will play important roles in meeting future requirements.

Future rail coal traffic

Through 1980, railroads anticipate a large increase in coal traffic, as illustrated by information developed during a recent survey of the major coal-carrying railroads sponsored by the Department of Transportation's (DOT's) Transportation Systems Center (TSC). 11/ The railroads surveyed originated 93 percent of the total 1974 rail coal traffic. 12/

*To offset losses experienced over the length of transmission lines, larger powerplants with greater coal consumption would be required than would be needed if bulk coal were transported to the user.

By 1980, these railroads anticipate a 95 percent increase over the 1974 coal traffic originations. The railroads' expectations may be optimistic* but they do indicate an awareness of the magnitude of their potential expansion needs. Their projections of 1980 coal traffic originations are shown below. 13/

Table 5

Originated Coal Traffic

<u>Rail district**</u>	<u>1974</u>		<u>1980</u>		<u>Percent increase</u>
	<u>Million tons</u>	<u>Percent of total</u>	<u>Million tons</u>	<u>Percent of total</u>	
Eastern	195	52.6	288	39.8	48
Western	66	17.8	279	38.5	323
Southern	<u>110</u>	<u>29.6</u>	<u>157</u>	<u>21.7</u>	43
Total	<u>371</u>	<u>100.0</u>	<u>724</u>	<u>100.0</u>	95

The railroads surveyed expect the most dramatic increase in originated coal traffic to occur in the areas served by western railroads--323 percent. This is attributable to development of the vast reserves of low-sulfur coal in the Western States--principally Montana and Wyoming. Coal from this region is expected to move more than 1,000 miles to markets in Midwestern and South Central States. 14/

* Railroads' plans may have been moderated since the TSC survey report was issued in April 1976. TSC has since undertaken a new survey of rail coal transportation needs through 1985.

**Western rail district consists of all States west of Mississippi River; Southern rail district includes Kentucky and North Carolina and all other States south, as well as east of Mississippi River; and the Eastern rail district includes all States north of Kentucky and North Carolina and east of Mississippi River.

Traffic increases originating on eastern and southern rail district lines, although not as spectacular as those anticipated in the West, will still be substantial. Eastern coal originations are projected to increase by 48 percent, principally from West Virginia, Pennsylvania, and Kentucky. Traffic originating on southern rail district lines is expected to increase by 43 percent, moving coal from Eastern and Central region coalfields to Southern and Southeastern States. 15/

Major coal traffic originations by State, as projected by the railroads, are shown in table 6. 16/

Table 6

Projected 1980 Rail Originated Tonnage by State

(States with over 1 million tons of rail originations)

<u>State</u>	<u>Rail originated tonnage</u> (millions)
Alabama	13.0
Colorado	20.2
Illinois	66.6
Indiana	17.9
Kentucky	119.8
Maryland	2.0
Montana	51.3
North Dakota	3.3
Ohio	25.3
Pennsylvania	57.6
Tennessee	7.5
Texas	8.1
Utah	14.2
Virginia	54.7
West Virginia	116.9
Wyoming	<u>135.0</u>
Total	<u>713.4</u>

The recent TSC-sponsored survey showed that in 1980 coal would generally move in the following patterns. 17/

Coal traffic originations by

Would move to markets in

Western rail district lines in

--Northern Great Plains coal fields

--Midwestern and South Central States

Eastern rail district lines in

--Appalachian coalfields

--36 States but predominantly to Midwestern and Atlantic Coast States

Southern rail district lines in

--Appalachian and Mideastern Interior coalfields

--Southern and Southeastern States

--Midwestern Interior coalfields

--Midwestern States

Railroad plans to meet 1980 coal transportation requirements

The railroads surveyed by TSC planned large investments in hopper cars, locomotives, and physical plant improvements to provide for additional coal traffic, as shown in table 7. 18/

Table 7

Planned Railroad Investment to Meet 1980 Coal Needs

<u>Investment category</u>	<u>Southern</u>	<u>Rail district</u>		<u>Total</u>
		<u>Western</u>	<u>Eastern</u>	
		(millions)		
Hopper cars (note a)	<u>b/\$667</u>	<u>b/\$1,044</u>	<u>b/\$1,189</u>	\$2,900
Locomotives	<u>b/60</u>	<u>b/539</u>	<u>b/66</u>	665
Physical plant	242	1,135	182	1,559
Maintenance facilities	<u>1</u>	<u>102</u>	<u>-</u>	<u>103</u>
	<u>\$970</u>	<u>\$2,820</u>	<u>\$1,437</u>	<u>\$5,227</u>

a/Includes replacement of retired equipment.

b/Estimated based on TSC survey breakdown of regional or hopper car/locomotive requirements.

The planned capital investment in physical plant shown above does not include Conrail's rehabilitation program which totals about \$4.9 billion over a 10-year period (See p. 5.19.) Conrail's program includes improvements necessary to move many commodities and does not relate exclusively to coal.

Western railroad expansion requirements

As noted before, the most dramatic increase in coal traffic is expected in the West. Their planned expansion requirements call for 29,000 new hopper cars 19/, 1,500 new 3,000-horsepower locomotives 20/, and over \$1.2 billion in fixed plant expenditures.

The major movers of western coal during 1975 are shown in table 8. 21/

Table 8

Principal Rail Carriers of Western Coal

	1975 coal traffic	
	<u>Originated</u>	<u>Total movements</u>
	(million tons)	
Burlington Northern	36.2	39.0
Chicago and Northwestern	3.8	16.1
Union Pacific	12.4	15.4
Denver and Rio Grande Western	<u>10.9</u>	<u>13.0</u>
Total	<u>63.3</u>	<u>83.5</u>

A recent study by the Federal Energy Administration's Office of Coal, entitled "Coal Rail Transportation Outlook," included the following comments on the status and problems of these lines: 22/

Burlington Northern

"The Burlington Northern is by far the most optimistic of the coal carrying railroads over expected traffic growth in that fuel during the next decade * * *.

"BN [Burlington Northern] predicts a growth in coal carried of from 16 million tons in 1974 to between 140 and 150 million tons by 1980. While no solid projections have been made beyond this, railroad spokesmen say that some predictions have indicated total coal volume of 225 million tons by 1985, and this is being used as a 'target.' * * * The company's track is generally in adequate condition for near term traffic needs, and is continually being upgraded. * * *

"Most of the BN's self-originated coals which, as noted, come from Montana and Wyoming, is delivered to Texas, the Northern midwest, and to Mississippi River points for transfer to other railroads or barges for final delivery. * * *

"Future competition may develop from coal slurry pipelines now being considered or planned for the west. BN says that 25 million tons of coal traffic per year, which one planned pipeline would haul from Wyoming to Arkansas, would mean \$150 million per year in coal freight revenue lost to the railroad. * * *

"BN expects unit trains[*] in operation to increase from 55 per week to about 200 by 1985. * * * To meet a five-fold coal traffic increase by 1982 would not pose insurmountable problems, since it is already expected to handle almost a four-fold increase by 1980. * * * The company now foresees a need to finance road and equipment improvements of about \$1 billion. This will include substantial ballasting and rail replacement work, on one route in particular. * * * It will be necessary to sell a large bond issue or issues to raise the necessary funds. * * *

"The BN, along with several other roads, also has advocated a statutory authorization of a freight rate structure that would make possible long term rate assurances to provide rail shippers with incentives for initiating and continuing rail use for substantial, predetermined periods.

*Defined as a complete train of dedicated cars on a regularly scheduled cycle movement between a single origin and a single destination. Coal unit trains typically consist of over 100 cars of 100-ton capacity each. 23/

"Under the Interstate Commerce Commission interpretation of the Interstate Commerce Act, freight rates are now filed for a 12 month period.* Although they are usually renewed at the same level, there is not assurance that they will be, and thus railroads feel they are at a disadvantage in negotiating coal carrying agreements at a specific and foreseeable level over a period of several years." 24/

Chicago and Northwestern
Transportation Company

"A large coal traffic increase is expected by 1985 due to the new 116 mile rail line to be constructed through the Powder River Basin coal deposits in Wyoming.* * *

Future coal traffic increases will originate along the new railroad line in Wyoming for Texas, Arkansas, Illinois, and Wisconsin markets. Present coal traffic volume is up over last year. A five-fold increase by 1982 would require a considerable investment to upgrade track and increase the number of hopper cars and locomotives. What is needed to accomplish such a feat are iron-clad contracts. Unit trains average about 35 per week and are on the increase. * * * No constraints are expected to coal traffic increases as the railroad is currently expanding. This expansion is contingent upon the coal production in Wyoming coming on line." 25/

Union Pacific Railroad

"Due to the increase anticipated for western coal production, a moderate increase in coal traffic is expected by 1985. * * * The rail beds are upgraded to carry 100 ton cars. Current track speed is 40 mph loaded and 50 mph empty. Continual upgrading of the track will allow this speed to increase slightly by 1985.

"The principal area of coal origin is southern Wyoming, and this coal is consumed in the Mid-west. Unit train use is on the increase and currently averages 23 per week. * * * A planned coal slurry pipeline will be in direct competition for coal traffic, and to a lesser

*According to the Interstate Commerce Commission, Burlington Northern is referring to "annual volume rates," which have been limited by the Commission to periods from 12 to 18 months. Annual volume rates require that a shipper in a designated period tender a specified amount of freight to qualify for a reduced rate.

degree so is the Burlington Northern, but there is no competing barge traffic. * * *

"A five-fold increase in coal carrying could be maintained without undue strain on the system. No significant constraints exist that would prevent the rapid expansion of coal traffic capacity.

"Here the potential coal traffic capacity exists. The problem is to get increased western coal demand and increased western coal production." 26/

Denver and Rio Grande Western Railroad

"Large increases in coal traffic are anticipated due to an expected increase in the use of low sulfur western coal by 1985. * * * The rails are set up to handle 100-ton unit train cars with a track speed maximum of 50 mph loaded and 70 mph empty. The tracks are continually being upgraded.

"Most of the coal originates in Colorado and Utah. * * * Unit train use is on the increase and averages 25 per week. * * *

"Corporate planning is indefinite due to the uncertainties of government actions and a national energy policy. The railroad maintains that if an energy emergency develops political action cannot substitute for a 2- to 3-year lead time required to plan, purchase, and manufacture the new facilities to carry expanded coal traffic." 27/

Western railroad expansion capability

A 1975 study by BOM concluded that:

"The capacity of the railroads to cope with substantially more western coal does not seem to be an unduly serious matter. The railroads can probably enlarge their capacity to handle larger amounts of coal as rapidly as their potential competitors [i.e., coal slurry pipelines] can be constructed. * * * This is not to imply that improvements in the western rail systems are unnecessary. But the basic requirements are there or can be met without having to endure long delays in meeting the conditions of high-standard service." 28/

Our discussions with selected western carriers--the Burlington Northern, the Denver and Rio Grande Western, and the Union Pacific--and with DOT officials of the Federal Railroad Administration and TSC corroborate this conclusion.

A key underlying factor is that less time is required to expand rail facilities than to construct new mines or electric utility powerplants.

However, western rail expansion will not be achieved without problems. These problems will include:

- Acquiring sufficient capital, hindered by uncertainties over future western coal development and slurry pipelines.
- The environmental impact of increased western unit train traffic.

Capital acquisition problems

Capital requirements for expanding the coal carrying capacity are larger in the West (see table 7, p. 5.10) than in the East and South, where lesser percentage of increases are expected (although Conrail will require massive investments).

DOT and railroad officials contended that the railroads' ability to raise capital could be affected by uncertainties as to future coal traffic volume caused by:

- Uncertainties as to the impact of air quality restrictions on the type and source of coal that will be demanded in the future (i.e. western low-sulfur coal versus eastern coal). 29/
- The possibility that coal slurry pipelines could receive the Federal right of eminent domain and threaten to draw off some of the profitable high-volume rail coal traffic. 30/
- The inability under the Interstate Commerce Commission's (ICC's) interpretation of the Interstate Commerce Act to enter into long-term (volume) rate agreements with shippers at reduced rates that would provide shippers with the incentive to initiate and continue rail use for substantial predetermined periods. 31/

Railroad practices which have tended to alleviate rail capital acquisition problems and shift the capital burden to shippers are:

- Ownership of unit train rolling stock by coal producers and utilities.

--Spur line financing by shippers, the cost of which is refunded by the railroads during an initial predetermined period of operation.

Uncertainty of the future role of western low-sulfur coal

Future governmental actions to resolve energy/environmental conflicts could have a major effect on demands for western coal. For example, a relaxation of air quality standards to permit greater use of high-sulfur eastern coal could substantially lessen anticipated demands for western low-sulfur coal. Recently enacted surface mining legislation will also affect western coal development. In view of the uncertainties in demand and the related lack of assurance of future traffic and revenues, the railroads face difficulties in planning and acquiring capital for expansion.

Uncertainty created by proposed, large-scale slurry pipeline development

Should the several proposed slurry pipelines (see p. - 5.22) be constructed, the railroads fear that the pipelines would draw off the more profitable high-volume coal traffic. Railroads contend that this uncertain prospect, valid or not, raises doubts as to future revenues, affecting the willingness of investors to provide capital for expansion. 32/

In addition, railroads point out that, in their role as common carriers, they would be required to carry increasing volumes of coal in the period before pipelines are constructed and would be faced with losing this business, curtailing operations, and laying off employees when pipelines are finally completed. 33/

Slurry pipeline advocates contend, however, that no railroad jobs will be lost because coal pipelines will not replace rail business. Railroads will handle increased coal traffic in the West even if slurry pipelines take a share of the expanding market. 34/

ICC prohibition of rail contract rate agreements

ICC's interpretation of the Interstate Commerce Act, which has precluded long-term contract rate agreements, denies railroads a tool which could facilitate rail planning and financing.

The act does not specifically authorize or prohibit railroad use of contract rates. However, ICC's interpretation of the act, as evidenced by previous commission decisions, is essentially based on the premise that contract rate agreements except in limited circumstances constitute a "destructive competitive practice," as described and prohibited by the National Transportation Policy. 35/

Railroads point out that, of the three cooperating businesses involved in coal transportation--the mining companies, the power companies, and the railroads--only the railroads are without long-term contract protection for their substantial investment. 36/ To encourage capital investment and thus assist in the rehabilitation and revitalization of the railway system, Congress enacted section 206 of the Railroad Revitalization and Regulatory Reform Act of 1976 (P.L. 94-210). This section, which adds subsection 15(19) to the Interstate Commerce Act, authorizes the publication of capital incentive railroad rates if a rail-related capital investment of \$1 million or more is made by carrier, shipper, or third party. Such rates may remain in effect for five years, subject only to adjustments to meet variable costs of the railroad. Railroads and shippers are thus assured a greater degree of certainty to predict the effect of a major investment on their future operations.

Long-term contract rate agreements could provide shippers with greater assurance of transportation costs at foreseeable levels and with the incentive to initiate and continue rail use for substantial predetermined periods. This, in turn, could provide railroads with assurance of long-term future revenues which the railroads consider necessary for planning and capital acquisition. 37/

Environmental impacts of expanded Western rail coal traffic

Most western coal output will be handled by 10,000-ton-capacity unit trains dedicated to continuous service between the mine and the user. 38/ FEA reported in its May 1976 "Coal Rail Transportation Outlook" that the four major western coal carriers were operating an average of 138 unit trains a week.

Table 9

Weekly Unit Train Traffic of
Principal Western Coal Carriers

<u>Railroad</u>	<u>Number of unit trains a week</u>
Burlington Northern	55
Chicago and Northwestern	35
Denver & Rio Grande Western	25
Union Pacific	<u>23</u>
	<u>138</u>

By 1985 unit train traffic is expected to expand several-fold. The Burlington Northern, for example, expects to operate about 200 unit trains per week by 1985.

Increased unit train traffic could have a major impact on communities en route, interrupt motor vehicle traffic, and subject community residents to increased noise and air pollution. Some Wyoming communities could experience coal traffic of between 30 and 48 unit trains a day in addition to other rail traffic. 39/

Public concern over the environmental impacts of increasing unit train traffic is causing citizens' and environmental groups to seek closer Federal scrutiny of coal traffic buildup. The Sierra Club, for example, has filed suit in the U.S. District Court to require ICC to more closely examine the environmental impact of a proposed 116-mile coal route to be jointly constructed by the Chicago and Northwestern and the Burlington Northern through the Wyoming coalfields. According to the Sierra Club, the route could carry as many as 48 trains daily through a number of small towns. 40/

Action will be required to reduce the safety hazards and disruption of vehicular traffic and community services that may be caused by unit train operations. Grade crossing improvements such as overpasses, crossing gates, and warning lights will be needed.

Presently, the railroads and affected communities disagree over who will bear the cost of these improvements. Railroads have contended that grade crossing improvements are not their responsibility, and affected communities seem unlikely to receive financial assistance from the rail industry. 41/ However, Federal funds are available to the States for construction of highway overpasses and grade crossing improvements under provisions of title 23, United States Code (which contains the Federal Aid Highway legislation), some of which could be used to help alleviate railway and highway crossing problems caused by unit train traffic.

Conrail's system rehabilitation needs

Increased coal production will require expanded rail transportation capabilities in the northeastern and midwestern areas served by Conrail, the federally subsidized consolidation of insolvent eastern and midwestern railroads established under the Regional Rail Reorganization Act of 1973 (Public Law 93-236). The Railroad Revitalization and Regulatory Reform Act of 1976 made \$2.1 billion available to Conrail for system rehabilitation. The United States Railway Association (USRA) has monitoring responsibility and authority over Conrail funding. According to a recent FEA coal transportation study, the Penn Central--the Nation's second largest coal handler and Conrail's major component--anticipates an increase in its total coal traffic from about 75 million tons in 1974 to 225 million tons in 1985. 42/

Deferral of maintenance by the insolvent lines has led to accelerated physical deterioration and operational deficiencies, thereby impairing Conrail's coal handling capability. FEA has observed that a large portion of Penn Central's track is in poor condition, causing reduced speeds and costly derailments. Massive upgrading of track and rolling stock are needed to assure that Conrail will be able to transport the projected volumes of coal. 43/

Conrail has undertaken a \$4.9 billion, 10-year program to upgrade and maintain its 16 State right-of-way. As part of the program, about 1,100 miles of rail will be improved annually. The program will be completed in 1985 and is expected to ultimately result in greater car utilization and faster service. 44/

However, right-of-way rehabilitation is given priority and is funded on the basis of traffic volume handled (i.e. those lines carrying the highest traffic density receive the highest priority). Conrail officials pointed out that coal lines were not, in all cases, among the highest density lines and may not receive the highest priority in rehabilitation planning. However, Conrail officials commented that additional rehabilitation of spur lines serving coal producers could be accomplished if the shippers provided funding which Conrail would refund during the initial five years of shipments. 45/

An FEA in-depth study of Conrail's coal transportation needs and plans is scheduled to be completed in 1977.

Conrail's rehabilitation requirements are numerous and the amount and timing of resource allocation to coal service could be critical to Conrail's future coal handling capability.

Availability of rolling stock to
move anticipated future coal output

Shortages of hopper cars have been mentioned as a possible constraint to transportation of future coal output. The existing fleet of hopper cars totals about 363,000, including railroad and shipper-owned cars. 46/ Either the fleet will have to be expanded or car utilization will have to be improved to accommodate future coal transportation demands.

Estimates of future hopper car needs can vary, depending on the assumptions made as to the trend of future car utilization. For example, BOM, in its "Coal Transportation Practices and Equipment Requirements to 1985," estimates that total hopper car requirements for coal production at the 1.2 billion-ton level could range from 604,500 to 642,500, assuming that current car utilization rates prevail through 1985. On the other hand, if the best possible car utilization is achieved, BOM estimates that about 25 percent of the total hopper car requirement, or 125,700 to 141,500 cars will be needed. 47/

It is clear that the railroad industry's ability to improve car utilization can dramatically change the number of hopper cars needed. On the basis of our review of existing studies and discussions with railroad and DOT officials, we believe the trend toward more efficient utilization will continue through further expansion of unit train operations and improved traffic management, and car requirements will be considerably less than BOM's estimated maximum requirement.

Using a study performed by the MITRE Corporation for the Department of the Interior as a baseline 48/, we estimated the following hopper car requirements needed to handle the scenario levels of coal output. 49/

Table 10

Estimated Hopper Car Requirements

as of 1985 and 2000

	<u>EEI</u> <u>scenario</u>	<u>BOM</u> <u>scenario</u>
1985	220,000	232,000
2000	229,000	263,000

The MITRE study assumes that most future increased coal traffic will be moved by unit trains.

Annual car-building requirements to provide replacements for retirements from the existing fleet and to add new cars to handle increases in coal traffic are projected as shown in table 11. 50/

Table 11

Average Annual Hopper Car Requirements

	<u>EEI</u> <u>scenario</u>	<u>BOM</u> <u>scenario</u>
Through 1985	15,600	16,600
1986 to 2000	16,000	18,300

Our discussions with the Federal Railroad Administration, the railroads, and representatives of the car-manufacturing industry indicated that the manufacturers have the capability to augment the existing fleet to meet future rail transportation needs. 51/ Freight car deliveries in 1975 tended to support this view. The car-building industry delivered more than 72,000 cars, of which 17,000 were open-top hoppers appropriate for coal service. Additional production capacity is available in the railroads' car-building shops. 52/

A recent study sponsored by the Electric Power Research Institute concluded that the railroad car-building industry would have the capacity to provide needed quantities of hopper cars (more than 20,000 cars a year). 53/

Railroads, moreover, can do much to improve car utilization and thereby reduce car requirements. Such improvements are available through expanded unit train operations, improved traffic management, and upgrading of railroad plant and equipment to permit faster, more reliable service.

COAL SLURRY PIPELINES AND WESTERN COAL DEVELOPMENT

Coping with the transportation of increased tonnages of western coal will pose problems that could be solved by several alternate modes or combinations of modes. 54/ Western rail lines have already embarked on expansion programs, and their unit trains are expected to move much of the anticipated traffic. Because of the magnitude, however, an alternative--the slurry pipeline--is now under consideration. Five new pipelines have been proposed, which could move as much as 75 million tons of coal annually. One proposed pipeline would move 25 million tons a year more than 1,000 miles. 55/ Advocates for such pipelines contend they are needed because the railroads will not be able to handle the anticipated western coal traffic. 56/

At present, only one slurry pipeline is operating in the United States--a 273-mile, 18-inch diameter line transporting 4.8 million tons of coal annually from mines at Black Mesa, Arizona, to a powerplant in Nevada. From 1957 to 1963, an Ohio pipeline moved coal 108 miles from Cadiz to Eastlake. It ceased operations because it was unable to compete with reduced railroad unit train rates. 57/

Like unit trains, slurry pipelines can be well suited to western coal transportation. Both modes can provide the relatively low-cost service per ton-mile that permits high volumes of cheaply mined western coal to compete in markets long distances away. 58/

However, slurry pipelines face critical problems. These problems relate to the need for the power of eminent domain to assemble rights-of-way, massive water needs in arid western areas, and technological and environmental problems of disposing of the effluent at the receiving end.

Slurry pipelines versus railroads-- advantages and disadvantages

Although selection of transportation modes is made primarily on the basis of cost, other factors also influence the choice of the optimum mode for a particular transportation requirement. 59/ Railroads offer the advantages of 60/

- an established, extensive, and expandable nationwide system;
- the ability to serve high- and low-volume applications;
- adaptability to multiple uses and to carrying commodities other than coal; and
- more job opportunities.

On the other hand, railroads have the disadvantages of 61/

- environmental problems as more traffic causes increased community disruption and noise and air pollution;
- greater exposure to inflation because a greater percentage of their operating costs are variable (e.g., labor); and
- topographical constraints from grading and track requirements causing indirect routing.

Slurry pipelines could provide the following advantages of 62/

- causing less air or noise pollution than railroads due to underground construction;
- greater inflation protection because a lower percentage of operating costs are variable; and
- more direct routing over difficult terrain.

Disadvantages of slurry pipelines may include 63/

- dependence on long-term, high-volume, continuous long distance coal movements to attain low cost of operations;

- service may be limited to single origin and single destination coal applications, since multiple sources and destinations would adversely affect cost;
- fewer employment and other economic benefits to communities en route;
- massive water requirements, sometimes in arid coal-producing areas; and
- environmental problems caused by massive water discharges at the receiving end.

Comparative costs

Available evidence does not clearly demonstrate the cost superiority of either unit trains or slurry pipelines. Relative cost advantages will depend on the specific circumstances of each application. 64/

A 1975 BOM study of alternative electricity costs based on five alternatives for western coal-based energy transportation indicated that there was little to choose between unit trains and slurry pipelines from a cost standpoint for a 25 million ton annual movement of coal 1,000 miles from eastern Wyoming coalfields. Two other modes of energy transportation using Wyoming coal--conversion to electricity near the mine and transport by extra-high-voltage transmission lines or conversion to gas at the mine and shipment by pipeline with subsequent conversion to electricity--were found to be more costly. The least costly method that BOM looked at involved mine-mouth gasification, transport by pipeline, and direct use for home heating, etc. 65/ The big differences between the cost of using coal gas directly as gas compared to various forms of electrical conversion raise some interesting analytical questions which GAO hopes to address in future work. GAO is particularly interested in an alternative that BOM did not look at, which involves transportation of coal to medium-size utility and industrial plants, gasification, and direct use of the gas.

According to the BOM study, the comparative consumer costs per million end use Btus for the alternatives studied, ranged as shown in table 12. 66/

Table 12
Comparative Costs for Western Coal/Energy
Transportation Alternatives

<u>Mode</u>	<u>Cost per million end use Btus (note a)</u> (1975 dollars)
Slurry pipeline/ conversion to electricity	\$ 6.18
Unit train/conversion to electricity	6.23
Mine-mouth conversion to electricity/shipment by wire	8.20
Mine-mouth gasification/ pipeline/conversion to electricity	11.28
Mine-mouth gasification/ pipeline/direct-use	2.87

a/Assuming all-equity financing.

Other studies do not agree with the BOM figures in table 12. For example, a 1976 Energy Research and Development Administration study shows significant cost advantages for slurry pipelines over unit trains for movements of over six million tons of coal per year over distances of 1,000 miles. 67/

The BOM figure of \$2.87 per million end use Btus for direct use of synthetic gas is low compared to other estimates. In 1976 GAO reported that the cost was expected to be from \$4.00 to \$5.00 per million Btus. 68/ A 1977 study by the American Gas Association estimates the cost per million Btus to be \$4.45 delivered at the residence, and \$6.95 when the end use efficiencies of home appliances are taken into account. 69/

The eminent domain question

Construction of long distance interstate coal slurry pipelines is presently constrained by developers' inability

to assemble necessary rights-of-way. Such pipelines would need to cross the rights-of-way of their competitors, the railroads, who resist pipelines passing beneath their tracks. 70/

Currently, seven States--West Virginia, Ohio, North Carolina, North Dakota, Texas, Oklahoma, and Utah--have granted the right of eminent domain specifically to slurry pipelines. 71/ As a result, slurry pipelines, which would have to cross several States, and many railroad rights-of-way, face tremendous obstacles in acquiring rights-of-way. Legislation granting the Federal right of eminent domain is seen by pipeline advocates as the most effective means of removing these difficulties.

A precedent was set in granting Federal eminent domain to natural gas pipelines. In the case of natural gas transportation, no other mode was feasible. 72/ However, with an expandable rail system already in place, such is not generally the situation for coal pipelines. The decision whether or not to grant eminent domain power to slurry pipelines, either generally or on a case-by-case basis, will involve a balancing of the economic and social advantages and disadvantages that pipelines and railroads have to offer.

Adequacy of water supplies for slurry pipeline use

Coal slurry pipelines require massive quantities of water--about one ton of water for each ton of coal moved. 73/ A coal pipeline moving 25 million tons of coal annually requires about 15,000 acre-feet* of water per year at its source. Much western coal development is expected to occur in semiarid western States, where water is in relatively short supply. Slurry pipeline demands would have to compete with public, industrial, and agricultural needs. The Bureau of the Census, Department of Commerce, has projected that the population of the Western States will increase at double the national average through the year 2000, further complicating the task of setting water use priorities. 74/

Fresh surface water in many coal-rich Western States is already totally committed or will be in the near future. Underground resources, or ground-water, have thus become an important source for the future, but there is inadequate information on their availability or the environmental effects of their use. Ground-water used in one area can affect supplies

*One acre-foot of water equals about 325,000 gallons.

hundreds of miles away. Large withdrawals in Montana or Wyoming, for example, could affect supplies in the Dakotas. 75/

In some cases, however, such as the Black Mesa to Nevada pipeline, water availability may not present insurmountable problems to slurry pipeline development. Water shortages therefore could constrain pipeline development in some, but not necessarily all, instances. Each application will require in-depth evaluation of the impact of pipeline withdrawals on present and future water requirements.

If water is unavailable at the point of slurry origination, it would be necessary to pipe water from an available source of supply. According to a recent DOT-sponsored study, piping water 300 miles from the Missouri River for use by the proposed 1,000-mile Wyoming to Arkansas slurry pipeline would raise its costs for each ton-mile by 25 to 40 percent. 76/ If slurry pipelines enjoy only marginal economic advantages over rail service--as suggested by BOM (see table 12, p. 5.25)--then the unavailability of water at the beginning of the system would make it uneconomical.

A possible substitute for fresh water in slurry pipelines is the saline ground-water that underlies many western coal regions. The extent of these resources and whether in fact they can be used have not yet been determined, however. 77/

Other possible alternative fluids under study as slurry mediums are oil, waste mine water, municipal and industrial waste water, and methanol. 78/

Environmental problems caused by disposal of slurry pipeline effluents

The other side of the problem of slurry pipeline water availability is what to do with the massive residual effluent at the slurry destination. As previously stated, about one ton of water is used for each ton of coal transported. Therefore, when the coal is removed from the slurry, most of the water transport medium must be disposed of.

This effluent contains fine particles of coal and other organics which pass through the dewatering stage. For a considerable time these fine particles remain suspended in the water.

Under current environmental restrictions on water disposal, such effluent cannot be directly discharged into natural water areas. A choice then must be made to either remove these particles by mechanical, chemical, or other means or to divert the water to ponds to permit the particles to settle out.

To remove the particles by additional processing, requiring the investment in ancillary plants, raises the question of whether the slurry system will be economical.

Diverting the water to settling ponds assumes the availability of the necessary land and the type of terrain necessary to create these ponds. A slurry pipeline would require many acres for this purpose, depending on the climatic conditions in the locality selected for the plant.

Another possibility that has been considered in situations where water supply at the mine is very restricted is to reuse or recycle the water from the delivered slurry by sending it back to the mine in a return pipe. This probably would be done only in unusual situations because of the considerable additional capital cost.

The Congressional Office of Technology Assessment (OTA) expects to complete a study of the railroad/slurry pipeline question by the end of 1977. The OTA study will evaluate

- coal production, transportation, and use needs and problems;
- the environmental impacts of slurry pipelines and railroads;
- the economics of both modes; and
- the legal implications (e.g., precedents and water rights).

FUTURE COAL TRANSPORTATION ON THE NATION'S WATERWAY SYSTEM

More than 100 million tons of coal are transported annually on the Nation's waterway system.* However, the

*There are very few places in the Nation where coal goes directly from mines to barges. Nearly all barge coal movements are preceded by a rail movement or truck transportation.

physical capacities of the system's locks and channels could limit its ability to move greatly increased quantities of coal on some parts of the system. Expected future growth in waterway tonnage would add to the need for expanded waterway facilities. 79/

Expanding waterway facilities would permit increases in coal and other commodity traffic, but such expansion is costly. For example, one of the bottlenecks on the upper Mississippi River is the Alton, Illinois, locks and dam 26. The Army Corps of Engineers' proposal to moderately raise its capacity from 73 million tons to 86 million tons by replacing the existing locks and dam would cost \$390 million. 80/ A study by the MITRE Corporation indicates that this lock is 1 of 13 on the Mississippi, Illinois, and Ohio Rivers where traffic levels are expected to reach lock capacity by 1985. 81/

It is not clear whether expanded waterway facilities will be essential to carry added quantities of coal. Parts of the existing system are presently under capacity and might be used to carry coal, depending on the origins and destinations of future coal movements. A DOT report on replacing the Alton locks and dam 26 suggests that much of the anticipated increased western coal output may not be transported through the Alton locks. Also some of the high-sulfur coals moved upriver to midwest markets may be displaced by lower sulfur coals. 82/ If major increases in development occur in eastern and/or midwestern coalfields rather than in the West, however, much greater demands may be placed on the inland waterway system. 83/

An official of DOT's Federal Railroad Administration has expressed concern that Federal expenditures to expand waterway capacity without an equitable charge to users would provide further advantages to the barge industry over competing railroads. 84/

It is claimed that the lower cost of barge operations (see table 3, p. 5.5) is partially attributable to the barge industry's use without charge of the inland waterway system, which is maintained by the Corps of Engineers, whereas railroads build, maintain, and pay taxes on their rights-of-way.

There is currently a bill (H.R. 5885) before the Congress that would require users of the Inland Waterway System to pay fees. This controversial bill has passed both the Senate and the House of Representatives, but was referred to a House/Senate conference on June 24, 1977. As of August 1, 1977, the bill was still in conference.

Care must be exercised to assure that expansion of railroads or waterways will not unfairly jeopardize the competitive position of the other. Assessments of impacts on the total transportation system are needed before informed railroad, pipeline or waterway expansion decisions can be made. The President has recognized the need for an assessment of the Nation's energy transportation needs and will create a commission to study and to make recommendations by the end of this year. One purpose of the study will be to develop means to encourage use of energy supplies nearest to consuming markets in order to reduce the need for long-distance transport.

SUMMARY

Potential increased coal production, particularly in the West, will place new demands on the Nation's coal transportation system that must be met through expansion of existing capabilities. Future coal transportation requirements can be met, but Federal action may be needed.

Transportation costs represent a substantial portion of the delivered price of coal. These costs range from approximately 25 percent of the cost of coal delivered from eastern coal fields to as much as 75 percent or more of the delivered price of coal shipped from Montana and Wyoming to electric utilities in the Midwest. A recent BOM study of western coal transportation alternatives indicated that slurry pipeline costs would be comparable to rail costs, while mine-mouth generation and shipment of electricity through extra-high-voltage transmission lines was found to be about 30 percent more costly. Other studies conclude that slurry pipelines would have an economic advantage in some cases.

In 1975, railroads carried about 65 percent of the coal traffic. Railroads will be the principal mover of coal in the foreseeable future as well. The waterway system (the least costly mode) does not directly service many of the areas scheduled for major coal development and it is limited in its capability to expand by the present physical capacity of its locks and by ice in the winter in some areas. Trucks and extra-high-voltage lines cannot compete in terms of price. And coal slurry pipeline development is constrained by difficulty in assembling possible rights-of-way as well as by shortages of water at points of origin, particularly in the West, and by environmental problems associated with the disposal of the effluent at the destination.

By 1980, railroads anticipate a 95 percent increase over 1974 coal traffic originations. Substantial investments in hopper cars, locomotives, and roadbeds will be required to handle the additional coal traffic.

GAO discussions with selected railroads and with the Federal Railroad Administration indicate that the railroads will be able to expand their coal handling capacity, even in the West where the increase will be most dramatic. An important consideration in this matter is that it takes less time to expand rail facilities than to construct new mines or electric utility powerplants. In the West, the social and environmental consequences of unit trains--interrupting motor vehicle traffic and subjecting community residents to increased noise and air pollution--appear to be a tradeoff for increased coal development.

Substantial investment in track and rolling stock will be needed. The railroads' ability to attract the needed capital to meet future coal traffic demand would be enhanced if the ICC lifted its prohibition on long-term rail contract rate agreements and if the future demand for western low sulfur coal due to air pollution regulations was less uncertain.

Increased coal production will also require expanded rail transportation capabilities in the northeastern and midwestern areas served by Conrail, the federally-subsidized consolidation of insolvent eastern and midwestern railroads. Conrail's rehabilitation requirements are substantial and the amount and timing of resource allocation to coal service could be critical.

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CHAPTER 6

HOW CAN WE MAKE IT USABLE?

The previous chapters have been concerned with the demand, availability, supply, and transportation of coal to available markets. Getting coal out of the ground requires new mines and expansion of existing mines. Transporting coal requires new transport systems and more intensive use of existing systems. Expanded use of coal means converting some electric powerplants and building new ones, and, to a lesser extent, constructing facilities for the manufacture of synthetic fuels. All these developments will require substantial capital just to build the facilities. There will also be great environmental and social costs--both monetary and nonmonetary. Perhaps the most important costs are nonmonetary--degradation of the environment and social changes that will occur in some areas, and the effects on public health and welfare which may occur due to increased coal use. Socioeconomic impacts are discussed in chapter 7.

When coal is mined, transported, and used, it usually produces environmental degradation of the land, air, and water, as well as increased water consumption--a particular concern in the arid West.

This chapter discusses major environmental problems, what is being done, what can be done to minimize the problems, who is doing it, and the cost.

Environmental problems discussed here are:

- The effects of burning coal on air quality and the effect that air quality regulation changes will have on coal development.
- Costs of air quality control technologies.
- The environmental effects of extracting coal and the impacts of State and Federal mining reclamation legislation.
- Water availability problems in the West.

Greater use of coal will entail some environmental compromises and socioeconomic adjustments. There are tradeoffs to be considered, balances to be struck, and prices to be paid. In the following section we discuss the impact of burning coal on air quality and the impact of air quality regulations on coal use.

AIR QUALITY

Coal is burned to produce heat and power for homes and industry. But, coal combustion also emits a number of potentially dangerous elements into the air that at sufficient concentration levels have been associated with increased incidence of respiratory diseases, and death rates in humans, crop damage, loss of domestic animals and wildlife, and deterioration of building materials.

The amount of emissions can be enormous. For example, annual sulfur dioxide emissions are estimated to be 150 million tons worldwide, of which 33 million tons are emitted within the United States. Coal-fired powerplants account for over 50 percent of the U.S. emissions. ^{1/} Coal burning must comply with Federal and State regulations to insure that environmental objectives are met.

Pertinent legislation affecting coal development

Beginning in 1963, the Congress enacted a number of laws to enhance and protect the quality of the Nation's air resources. These actions range from authorizing Federal emission control research to establishing national air quality standards (pollution concentration levels). The law which most affects current coal combustion is the Clean Air Amendments of 1970, as amended (42 U.S.C. 1857), which directed the Environmental Protection Agency to establish minimum national air quality standards.

EPA established primary and secondary standards for six classes of pollutants--sulfur dioxide, particulate matter, carbon monoxide, hydrocarbons, nitrogen oxides, and photochemical oxidants. Primary standards were set at levels necessary to protect the public health and were to be met no later than July 1, 1975. Secondary standards were designed to protect the public from such adverse effects as crop damage, reduction in atmospheric visibility, and corrosion of materials. Secondary standards were to be met in time frames considered reasonable by EPA.

While the national ambient air quality standards were established to protect the health and welfare of the Nation, it is difficult to identify conclusively the threshold level of concentration for each type of emission below

Note: Numbered footnotes to ch. 6 are on pp. 6.52 to 6.54.

which adverse health effects will not occur. In addition, the area of long-term or genetic effects of exposure to the emissions is not known since the present state of knowledge allows only an approximate estimate for such effects.

Under the 1970 act, States were responsible for achieving the standards by developing State implementation plans (subject to EPA approval or modification) which included programs and timetables for meeting the Federal standards. Implementation plans to attain and maintain these standards have been submitted by all the States, but both primary and secondary standards have not yet been attained in many regions (not all plans were approved by EPA).

In addition to the national ambient standards, the Clean Air Act of 1970 directed EPA to establish (1) standards of performance for new or modified stationary sources of pollution to insure that they are designed, built, equipped, and maintained so that minimum emissions occur, regardless of the source locations (new source performance standards) and (2) air quality standards for controlling other hazardous emissions, which would include coal combustion. The new source performance standards were set at levels which will require installation of the best systems of emission reduction which the Administrator of EPA has determined as being adequately demonstrated. Cost factors are considered in making this determination. Standards for controlling other hazardous emissions from coal combustion will be promulgated as data regarding their effect become available.

Two of the most significant impacts of the Federal regulations and the State implementation plans involve controlling sulfur dioxide and particulate emissions. For utilities to be operated in compliance with these standards:

- A large number of plants probably will have to install flue gas desulfurization technology, a method of cleaning coal combustion gases, to meet sulfur oxide emission requirements. (Low-sulfur coal supplies would have to be developed very quickly to provide a means of complying with the emission requirements short of desulfurization.)
- All plants must install particulate scrubbers electrostatic precipitators, fabric filters, or bag houses to meet particulate matter standards.

Available control technologies for reducing coal combustion emissions

Electric utilities that use coal have limited alternatives in complying with national ambient air quality standards and new source performance standards for sulfur oxides, particulates, and nitrogen oxides emissions. EPA believes that meeting the applicable standards requires the installation of controls on nearly all new coal electric powerplants through the 1970s and on many existing plants. President Carter's National Energy Plan recommends that all new coal burning facilities, including those that burn low-sulfur coal, be required to use the best available control technology. 2/ A summary of available technologies for controlling these emissions follows.

Sulfur oxides emissions

Sulfur oxides emissions are directly related to the sulfur content of coal being burned, and there is little in the way of conventional boiler design or operation that can influence the level of emissions from coal during combustion. 3/

Most electric utilities now try to meet sulfur oxides ambient air quality standards by using coal with lower sulfur levels, reducing sulfur content before combustion (washing and blending), collecting emissions following combustion (scrubbers), or by tailoring emissions to current meteorological conditions to maximize natural atmospheric dispersion (intermittent controls). Using tall smoke stacks is another method for maximizing atmospheric dispersion. None of the dispersion measures reduces pollution, except locally; they just spread it around.

Particulate emissions

Various particulate control devices have been installed on nearly all coal-fired boilers to collect microscopic ash particles emitted during coal combustion. The specific method is largely determined by the sulfur oxides control method selected by an electric utility. For example, electrostatic precipitators are expected to be installed on powerplants which use low-sulfur coal for sulfur oxides compliance and a particulate scrubber will be installed in combination with a sulfur oxides scrubber at other locations. The particulate control devices are much less effective in collecting finer particulates (1 micron or smaller).

Nitrogen oxides emissions

According to EPA, there are no true nitrogen oxides scrubbing processes available at an economically viable price. Emission of nitrogen oxides can be significantly influenced by boiler design and operating conditions. The major factor, however, affecting nitrogen oxide formation is the temperature of combustion. ^{4/} Although several methods exist, many electric utilities are expected to choose one of two available compliance methods to meet nitrogen oxides emission standards--both require changes in boiler operation. The methods, although not always effective, involve retarding formation of nitrogen oxides near the flame by controlling the air/fuel ratio--reducing the excess air--thereby leading to lower nitrogen oxide formation.

ECONOMIC AND ENVIRONMENTAL EFFECTS OF COAL DEVELOPMENT

GAO developed estimates of effects of increased coal use by electric utilities on production costs and pollution levels under two coal demand scenarios. Demand data for 1985 and 2000 were developed by using the Bureau of Mines scenario ^{5/} and a second scenario for 1985 based on industry estimates of planned additions to generating capacity. The demand levels are:

	<u>Coal Electric Demand</u>	
	(quadrillion Btus)	
	<u>1985</u>	<u>2000</u>
Industry plans ^{6/}	12.9	(a)
Bureau of Mines	15.7	20.7

^{a/}A demand "planned" projection was not made by industry for the year 2000.

The cost of pollution control equipment for an individual powerplant may vary widely* depending on several factors, including

*For example, in a 1975 analysis performed for EPA by Pedco Environmental Specialists, Inc., scrubber costs ranged from \$33,000 to \$205,000 per megawatt of capacity.

- specific sulfur dioxide control technique used;
- pollution emission removal requirements for sulfur oxides and particulate matter;
- condition of terrain and subsurface;
- status of the powerplant, new or existing;
- system reliability; and
- management preference.

On an aggregate basis, however, a rough approximation of compliance costs may be projected by multiplying the capacity expected to use each compliance method by a representative cost for that method.

The electric utilities' cost to control emissions in compliance with national standards can be categorized into capital costs, and operating and maintenance costs. Capital costs include the cost of pollution control equipment; energy penalties (added capacity to operate control equipment); capacity losses (cost associated with compensating for a reduction in effective capacity caused when switching from high to low-sulfur coal when the Btu heat value is reduced by 15 percent or more); and boiler modification costs (changes in plant configurations and material handling equipment required for use with larger amounts of low-sulfur coal).

Under the BOM scenario, we estimated the cumulative capital costs for emissions control* to be about \$19.1

*Although powerplants placed into service in 1977 or later will be required to comply with EPA emission regulations for nitrogen oxide, these costs are for sulfur oxide and particulate control only. EPA, however, estimates that the electric utility industry will invest \$450 to \$500 million between 1975 and 1985 to comply with nitrogen oxides emission standards.

billion* by 1985 and \$26.4 billion by 2000. Annual operating and maintenance (O&M) costs for this scenario would amount to approximately \$1.3 billion in 1985 and \$2.3 billion by 2000. Comparatively, the cost impacts under the industry planned projection for 1985 are \$15.9 billion for capital expenditures and \$1.1 billion annually for O&M cost.

In commenting on our report, the Federal Power Commission questioned the accuracy of several elements in our cost analysis. The FPC has recently issued a report on flue gas desulfurization technology in which actual planned scrubber capacity and cost figures were obtained from electric utilities. Consequently, FPC believes that the megawatt capacity expected to retrofit to scrubbers is overstated by about 10 times (39,000 MW versus 4,200 MW), and the unit cost for scrubber installation is understated by about 23 percent (\$70 per kw versus \$90 per kw.) Our cost estimates were based on figures from a May 1976 EPA report entitled "Economic and Financial Impacts of Federal Air and Water Pollution Controls on the Electric Utility Industry", and our estimates of installed generating capacity by 1985 and 2000. In any event, the dollar difference (about \$350 million) between the two calculations is a relatively small part of the total multibillion dollar capital outlay we are talking about.

The impact of these emission control costs will not be felt uniformly across the Nation. Costs to control sulfur oxides and particulate emissions will vary widely between geographic regions due to variances in existing capacity and projected additions. For example, existing coal-fired electric generating capacity among the nine Bureau of the Census regions ranges from a low of 0.6 percent in the Pacific region to 30.3 percent in the East North Central region. Percentage changes to capacity under the scenarios also

*Costs are 1975 dollars and reflect the following composite of control technologies utilized:

Scrubbers	39 percent
Low-sulfur coal	22 percent
Medium-sulfur coal	8 percent
Washing and blending	9 percent
No controls	<u>22 percent</u>
	<u>100 percent</u>

vary widely. Consequently, the economic impacts differ widely among regions. The following table illustrates these variances for both the BOM scenarios and the industry estimate.

Table 1

	<u>Regional Ranges</u>			
	<u>Capital costs</u>		<u>O & M costs/year</u>	
	<u>From</u>	<u>To</u>	<u>From</u>	<u>To</u>
	(millions)	(billions)	(millions)	
1985 BOM	\$36	\$4.9	\$1.7	\$353
1985 Industry plan	12	4.0	.3	305
2000 BOM	72	6.9	3.8	600

In seven of the nine regions, control of sulfur oxides accounts for the major portion of the capital expenditure. In the remaining two regions, controlling particulate matter accounts for the major cost allocations.

Impact on consumer cost for electricity

Regardless of the elements and distribution of the costs incurred to meet air quality standards, these costs represent a major investment which will be passed on to the consumer by the utility companies. Based on the total pollution costs of procuring and operating pollution control equipment under the 1985 BOM and 1985 industry plan scenarios, the average residential consumer electric bill could increase by 3.61 and 4.04 mills per kilowatt hour, respectively.* These pollution control costs will represent increases of about 9 and 10 percent, respectively, in the average residential consumer's electric bill in 1985 under the two scenarios. The increase for certain electric systems may be substantially greater, however.

*GAO calculations based on information contained in a May 1976 EPA publication.

Levels of pollutants emitted
during coal combustion

The amount of pollutants emitted during coal combustion can be enormous, even with control technology. Even more staggering is the sludge problem created when control technology, such as scrubbers, is employed. The following table puts these problems into perspective (with and without control technology) under the two 1985 scenarios and the BOM scenario for the year 2000:

Table 2

Table of Emissions Levels (note a)
(GAO Calculations)

	Annual Emissions		
	1985 <u>Industry plan</u>	1985 <u>BOM</u>	2000 <u>BOM</u>
	Pollutants ----- (tons) -----		
Using No Controls (note b)			
Sulfur oxides	26,058,000	31,714,000	41,814,000
Particulates	1,060,380	1,290,540	1,701,540
Nitrogen oxides	4,760,100	5,793,300	7,638,300
Carbon monoxide	264,450	321,850	424,350
Solids	65,145,000	79,285,000	104,535,000
Using Controls (note c)			
Sulfur oxides	2,605,800	3,171,400	4,181,400
Particulates	265,740	323,420	426,420
Nitrogen oxides	4,760,100	5,793,300	7,638,300
Carbon monoxide	264,450	321,850	424,350
Solids	188,340,000	29,220,000	302,220,000

a/Calculations were made by multiplying the rate of emissions by the quadrillion Btu level associated with each scenario.

b/Conventional steam powerplant burning coal with an ash content of 12.53 percent and sulfur content of 2.59 percent.

c/Conventional steam powerplant using a wet limestone scrubber system. Coal burned is the same as with no controls.

Solid wastes without controls consist of coal soot and fly ash. Solid wastes in systems where control technology is employed include sulfur, particulate matter, and limestone, as well as the soot and ash. As the table above shows, using controls for sulfur and particulates nearly triples the amount of solids which must be handled. To put the solids problem into perspective, the waste material generated under the 1985

industry plan scenario with controls is about equal to the tons of municipal waste generated by all the people in the United States during the course of one year. Land availability and disposal costs of such wastes is a significant problem which industry and government must address.

AIR QUALITY: PROBLEMS AND CONCERNS

Emissions control is the principal area of concern with regard to coal-related air quality objectives. Providing adequate controls requires large expenditures to develop and procure pollution control equipment. Several concerns regarding future coal development are raised by current Federal standards as well as future changes. They are:

- The impact future changes in air quality regulation will have on coal development.
- Conflict of air quality objectives with coal development objectives.
- The effect of possible regulation of trace elements and other uncontrolled emissions on future coal development.
- The effect of sludge disposal on coal development.

Modifications to air quality regulations

During the 95th Congress, the Clean Air Act was amended to adopt revised procedures for preventing significant air quality deterioration from new sources of pollution (P.L. 95-95, August 7, 1977).

EPA regulations--promulgated in 1974--set allowable pollution concentration increments which may not be exceeded by a major new source for three classes of geographic areas. Briefly, class I areas would allow little or no change in air quality levels, class II applies to areas where a moderate change would be tolerated, and class III applies to areas where air quality would be allowed to deteriorate up to the national standards. The EPA regulations initially designated all areas as class II, subject to redesignation to class I or class III at the initiative of a State or local authority. EPA anticipated that class I redesignations would be made to protect existing clean air resources in areas such as national parks and wilderness areas. Class III redesignations would occur where State and local policies allowed extensive industrial development, but pollution levels could not exceed national ambient air quality standards.

The Clean Air Act Amendments of 1977 retain the three classes of geographic areas but allow for variances from some class I areas. The variances can allow some class I air quality standards to be exceeded up to 18 days per year for sulfur oxides.

A few areas (national parks, wilderness areas) are designated mandatory class I. All other areas are initially designated class II, subject to reclassification by individual States. A new facility must obtain a construction permit in any area subject to the significant deterioration provisions. The permit can only be obtained if it is demonstrated that the new source will not interfere with maintenance of the area classification.

The new amendments require new fossil-fuel boilers to meet a numerical sulfur oxides emissions limit (such as pounds of emissions per hour), and if the plant can meet the emissions limit by burning low-sulfur coal, some treatment must still be applied to reduce emissions by some unspecified percentage. This additional percentage reduction will be determined by EPA. The new sources can meet the new requirement by any method which need not necessarily be scrubbers.* The control used must be continuous rather than intermittent.

While most of the emphasis concerning future changes in air quality regulations focuses on the desire for more stringent controls or standards, one school of thought favors relaxation of requirements by allowing the use of intermittent control systems.

Intermittent controls do not significantly reduce total emissions but tailor them to current meteorological conditions to avoid violating (ground level) ambient air quality standards. When meteorological conditions are favorable, natural atmospheric dispersion of sulfur oxides emissions would enable the standards to be met at ground level. During periods of unfavorable meteorological conditions, sulfur oxides limitations would be met by using a temporary supply of low-sulfur fuel or curtailing operations and shifting the electrical load to another powerplant.

*Capital costs for installing scrubbers on all coal-fired powerplants would be \$23.67 billion under the 1985 industry plan scenario and \$25.4 billion and \$35.0 billion under BOM's 1985 and 2000 scenarios, respectively (our calculations).

At first EPA rejected their use, believing the systems were unreliable and unenforceable. Now EPA believes that sufficient advances in monitoring systems have been made to allow the use of intermittent controls as an interim compliance method for a limited number of plants only until continuous emission control technology is installed. The intermittent control systems would be feasible at relatively isolated plants which contribute a major proportion of sulfur oxides in their area.

EPA and the Energy Resources Council recommended to the Congress in 1975 an amendment to the Clean Air Act, which would permit use of intermittent controls on an interim basis with permanent controls required by 1985; however, no congressional action was taken. Over and above EPA's proposal, the utility industry supports intermittent control techniques as a permanent means of compliance and not just limited to an interim period of 10 years. The industry believes intermittent controls would represent a cost compromise while still maintaining some control over emissions.

The problem

The concern raised by future modifications of air quality legislation involves the effects they would have on both U.S. coal development and air quality. According to 1976 EPA estimates 7/, changes to Federal air quality standards would have increased the electric utility industry's capital requirements from 1975 to 1990. The increase was primarily related to the required use (on a case by case basis) of the best available control technology for new pollution sources. Specifically, EPA estimated that the industry's capital requirements would have been increased by \$11.2 to \$11.6 billion. These figures represent an increase of about 3 percent in the industry's planned capital expenditures.

Proponents of the more stringent regulations believe they would minimize air quality deterioration while maintaining establishment of coal-fired utilities and their adequate economic development. Opponents argue that the regulation would decrease coal production, increase U.S. consumption of imported oil, and increase costs for controlling emissions. 8/

Concerning the implications of using intermittent controls, EPA estimated 9/ that, depending on the option adopted, capital expenditures for control technology could be reduced by between \$1.3 and \$1.8 billion over the short run in favor of higher (\$1.9 to \$3.1 billion) expenditures over the long run, since both intermittent and permanent controls will have been financed.

Proponents of intermittent controls contend that these controls consume less energy, are less expensive, and are immediately available. Industry, with some exceptions, argues that scrubber technology is not sufficiently reliable to require widespread installation, and that advanced coal combustion technologies will not be commercially available before 1985.

Opponents of intermittent controls maintain that, while they are less expensive, the use of intermittent controls does not significantly reduce total emissions but merely disperses them at opportune times. This constant input of emissions into the air may cause or aggravate pollution hazards caused by area sulfate concentrations (e.g., health, visibility, acid rain, climate changes). 10/ This argument is strengthened by an incomplete knowledge of the potential effects of such increased concentrations. Although intermittent controls may represent a compromise of short-term cost impacts, many argue that they could in fact compromise our environment and well-being in the long run.

Most of the above points regarding intermittent controls also apply to use of tall stacks, which basically export the problem downwind.

Conflicting environmental and coal development objectives

A problem which must be considered regarding future coal development and its impact on air quality is the apparent conflict between maintaining air quality and utilizing increasing amounts of domestic coal resources. This conflict is manifested at two levels: State versus Federal, and within the Federal Government itself.

The States' rights to maintain better air quality than required by the Federal Government have always been protected in Federal air quality legislation, but the implications of States' rights may influence the Nation's ability to meet its energy objectives. For example, some State implementation plans have established sulfur oxides emission regulations which are more stringent than necessary to achieve national primary standards. In 1975, EPA estimated

that about 124 million tons of coal burned annually by electric utilities to comply with State emissions regulations could have been replaced by coal with higher sulfur content without exceeding national ambient air quality standards. 11/ Thus, lower sulfur coal would be freed for use by other facilities which otherwise would either burn another fuel, or install expensive control technology. Consequently, the EPA Administrator was directed by the Congress, under the Energy Supply and Environmental Coordination Act of 1974, to review each State implementation plan and report to the State whether such plans could be revised to allow use of higher sulfur fuels without interfering with the attainment and maintenance of national ambient air quality standards.

In reviewing the State implementation plans, EPA identified three reasons for the existence of regulations more stringent than necessary to meet the national air quality standards

- the adoption of State ambient air quality standards more stringent than national standards;
- the use of stringent emission regulations required to maintain air quality in an industrialized section of a State as the regulation for the entire State, including less industrialized regions; and
- use of large, isolated sources in an air quality control region as the basis for establishing regulations for the entire air quality control region.

As a result of EPA's encouragement, however, many States have revised or submitted for revision their implementation plans allowing higher sulfur coal to be substituted for up to 113 million tons of lower sulfur fuel annually. 12/

The apparent discord between environment and energy development objectives is not just limited to EPA and the States, but also within the Federal Government--between the Federal Energy Administration and EPA. FEA is responsible for increasing reliance on domestic energy sources, and therefore has pressed EPA to effect additional revisions of State implementation plans. In fact, an FEA official noted that, while progress has been made, FEA is not satisfied that all States with potential revisions have been identified.

EPA is trying to cooperate with national energy programs but is charged with responsibility for giving primary consideration to achieving and maintaining national primary standards in accordance with the Clean Air Act. Therefore, in reviewing proposed State implementation plan revisions, EPA has allowed relaxation of sulfur oxides emission regulations only to the extent that national air quality primary standards are still maintained.

Uncontrolled coal emissions may influence future coal development

Coal emissions not currently regulated can be categorized into three areas--trace elements, fine particulates, and other emissions. Should these emissions be regulated, they will influence the extent to which and the manner in which coal will be developed and used in the future.

Trace elements

In addition to the previously discussed air pollutants (sulfur oxides, nitrogen oxides, particulate matter) caused by coal combustion, a number of other elements such as mercury, lead, beryllium, arsenic, fluorine, cadmium and selenium (called trace elements) may be emitted as a result of the inorganic mineral composition of coal. There are about 53 commonly known trace elements which have been associated with coal. Although available data show trace elements to be a potential problem, more knowledge is needed on sources, formation, and transport of trace elements before control options and emission tolerance levels can be addressed in an ideal way.

Only limited research and development efforts have been undertaken in trace elements. (See p. 6.48.) Although, not a trace element itself, a discussion of the sulfate problem can serve to illustrate the magnitude of this lack of knowledge and the associated problems of implementing trace element and other emission regulations.

Sulfates related to coal combustion occur as a result of sulfur dioxide emissions which are converted to sulfates by various chemical processes. About 150 million tons of sulfate equivalents are emitted each year into the atmosphere. The majority of the acidic sulfates* are attributed to coal

*Those sulfates which contribute to the acid rain problems and, therefore, are most harmful.

combustion facilities. The emissions not only affect the human and natural environment but also reduce visibility and may possibly modify the climate. Sulfate control in the atmosphere may not depend only on the control of sulfur dioxide but on control of precursors such as fine particulates and nitrogen oxides. Therefore, even with proper enforcement of State implementation plans and new source performance standards, EPA projects the sulfate levels in 1990 to be similar to the 1975 level--a level which may cause serious health problems.

EPA's position is that there is enough knowledge on the effects of sulfates to recognize that they are a threat to the health and welfare of the Nation. However, this knowledge is not sufficient to quantify levels at which sulfates should be controlled nor how to control sulfates to maintain such a level. This reluctance stems from uncertainties of the solution and poses a significant public policy issue, that is, what level of proof is necessary to establish that an element is harmful before EPA is justified to promulgate a national standard?

Specifically these unknowns include the following points:

- Field measurement technology is not available.
- The atmospheric chemistry and meteorology involved in conversion of sulfur dioxide and hydrogen sulfide to sulfates is uncertain.
- The health effect of exposure to given levels of specific sulfate compounds over given periods of time cannot be specified.
- The interrelationships between sulfates and other pollutants in inducing adverse health effects are unknown.

Similar problems regarding trace elements are even more complicated because the knowledge and research on them is generally less than known about the sulfate problem. To put the magnitude of these emissions into perspective, we developed estimates of the tons of trace element emissions under three scenarios. (See table 3, p. 6.17.)

Table 3

Calculated Annual Emissions of Selected Trace Elements
for 1985 and 2000 Energy Scenarios (note a)

Potential annual emissions (tons)

<u>Substance</u> <u>emitted</u>	<u>1985</u> <u>EEI</u>	<u>1985</u> <u>industry</u> <u>plan</u>	<u>1985</u> <u>BOM</u>	<u>2000</u> <u>EEI</u>	<u>2000</u> <u>BOM</u>
Antimony	28,195	31,229	38,127	20,680	38,500
Arsenic	4,229	4,684	5,718	3,102	5,770
Beryllium	12,686	14,051	17,155	9,305	17,320
Bismuth	352	389	475	258	480
Chlorine	140,997	156,145	190,633	103,399	192,530
Lead	21,147	23,422	28,595	15,510	28,880
Mercury	282	313	382	207	380
Tin	21,147	23,422	28,595	15,510	28,880

a/The emissions shown here state only the weight of the element itself and have been calculated utilizing emission figures for a 1,000 MW generating plant without emission controls burning 8,000 Btu/lb. coal at a 65 percent load factor and a 10,000 Btu heat rate. The "potential" figures shown in the table are the high end of the range of emissions calculated for each substance.

Particulates

Fine particulates (soot and fly ash less than 3 microns in size) may be a health hazard because, in contrast to coarse particulates (3 microns or larger), they bypass the body's respiratory filters and penetrate deeply into the lungs. In addition to their own innate toxicity, their porous character enables them to act as a transport mechanism for more toxic substances which otherwise might have been filtered in their natural state. Fine particulates also remain airborne for extended periods of time, obstructing light, and causing problems with visibility--haze and smog. In addition, because they scatter and absorb both solar and terrestrial radiation, they affect the earth's heat balance in what has been called the "icebox effect." Moreover, greater amounts of rain and snowfall have been observed in areas where particulate emissions have been heavy.

Technology exists today to partially control fine particulate emissions. However, even when the best available high efficiency collection devices are used, 1 to 2 percent of the particulates are not captured. These particulates are for the most part less than 1 micron. EPA is conducting research to control these finer particulate emissions, but to date their efforts have been limited.

Other emissions

Coal combustion produces the emission of other elements and gases which may have an adverse effect on our environment. These are emission of uncontrolled elements such as carbon dioxide, and waste heat discharged during electric power generation. There are, in addition, estimates that coal burning plants emit more radiation than oil burning plants. The implications of these other emissions are not clear, but the National Academy of Sciences has recently released a study on the effects of carbon dioxide. 13/

Carbon dioxide--Whenever fossil fuels are burned, carbon dioxide is emitted. While some carbon dioxide is absorbed by plant life and the oceans, much of it accumulates in the upper atmosphere. These carbon dioxide concentrations intercept heat radiation from the earth, trapping the heat within the atmosphere causing what has been termed as a "greenhouse effect." Accurate projections of carbon dioxide's impact on global temperatures are not possible because of limited knowledge; however, it is known that temperatures increase with rising carbon dioxide levels. For example, a global warming of 1 degree to 2 degrees centigrade could cause serious repercussions on the earth's surface including shifting of wind circulation belts and redistributing temperature patterns and precipitation levels. Numerous secondary effects associated with these primary effects will also occur. An example of the effects of even a relatively small climatic change (temperature changes of tenths of a degree), may be the recent failure of Russian grain crops which were largely attributable to small climatic fluctuations in marginal growing areas.

Worldwide,* the increased global temperature caused by rising concentrations of carbon dioxide may produce some melting of the polar ice caps, causing a sea level increase of tens of feet, gradually inundating coastal plains and low lands, and perturbation of marine biology. With continued growth in the use of fossil fuels, the effect of increased coal combustion on climatic conditions may become an important problem during the next 50 years.

Waste heat generation--During power generation, much of the energy released by the burning fuel is converted into waste heat rather than electrical energy. Currently, the best overall thermal efficiency of fossil-fuel plants is about 40 percent, with many older plants operating at efficiencies considerably less than that. The waste heat is partially dispersed through the smokestacks into the air. Most of it, however, is released into rivers or lakes by water flowing through condensers (used to change steam back into water) and returning to its source at a much higher temperature (an average of 15 to 20 degrees Fahrenheit higher).

*It is speculated that the effects of carbon dioxide in the Northern Hemisphere are counteracted for the most part, by the effects of the large amounts of particulate matter in the atmosphere. In the Southern Hemisphere, where particulate matter is not a problem, temperature increases are potentially greater.

Unlike air pollution from fossil-fuel steam plants, waste heat released to the atmosphere is not considered directly dangerous to public health. The primary problem caused by waste heat released into water is its effect on aquatic life.

While the effects of increased water temperatures on aquatic life are not known with great precision, the extent of damage is determined by the relative water temperature and volume released compared to the temperature and size of the receiving lake or river. Water temperature changes, long-term or short-term, will alter the composition of fish and algae population. This occurs not only because the warmer water reduces the amount of oxygen in the water (proving lethal to some species) but also because various fishes will no longer be able to reproduce or compete with other types. In addition to fish damage, temperature variations affect the growing conditions of plant life in the water. Guidelines for control of water pollutants, including thermal pollutants, were established pursuant to the provisions in the Water Pollution Control Act of 1972.

Dispersion of waste heat into the atmosphere also has potentially adverse effects, especially in urban areas. This heat dispersion, which can compose up to 15 percent of the heat generated during the combustion process, can affect the atmosphere and climate of a locality by contributing to what is known as a "heat island effect". This phenomenon occurs when pockets of warm air settle over an area, increasing the atmospheric temperature and decreasing the air pressure, thereby influencing the local weather and pollution patterns.

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The emission of harmful elements and gases into the air raises questions regarding the desirability of increasing reliance on coal as an energy source and the cost of controlling the harmful emissions. The questions are magnified by the extreme lack of knowledge regarding both trace elements and other currently uncontrolled emissions.

The environmental aspects of sludge generated by air quality control technology

Handling and disposal of solid wastes (sludge) from flue gas desulfurization units (scrubbers) is a complex problem complicated by land availability and disposal costs. Scrubber waste consists of three general types of material: fly ash, calcium sulfate/sulfite salts, and scrubbing liquor associated with the partially dewatered and chemical characteristics. For example, trace elements are found almost exclusively in

the fly ash. The calcium sulfite has very poor physical properties resulting in inadequate dewatering and structural stability features and the liquor contains concentrated dissolved salts produced from the scrubbing process. Despite these complexities, disposal and treatment methods have started to evolve. However, until the characteristics of each sludge component are understood, problems such as trace element leachability, sludge dewatering, and beneficial use of scrubber wastes cannot properly be addressed.

EPA, as well as several other public and private concerns, has initiated field evaluation projects on this waste disposal problem. EPA, for instance, has established a powerplant site field evaluation of the disposal of untreated and treated flue gas cleaning wastes. This program began in September 1974 and is scheduled to continue to mid-1977 to verify the environmental effects of several disposal techniques and scrubbing operations, and to develop cost estimates of alternative disposal methods.

EPA estimates total sludge fixation and disposal costs at between \$7.30 and \$11.40 per ton of waste (dry).^{*} Applying this cost range to the scenarios, the annual cost for solid waste disposal would be as follows:

Table 4
Calculation of Annual Waste Disposal Costs
for 1985 and 2000 Scenarios

	1985		2000	
	<u>From</u>	<u>To</u>	<u>From</u>	<u>To</u>
	-----millions-----			
<u>No controls</u>				
Industry plan	\$ 475.6	\$ 742.7	\$ -	\$ -
BOM	578.8	903.8	763.1	1,191.7
<u>Using controls</u>				
Industry plan	1,374.9	2,147.1	-	-
BOM	1,673.3	2,613.1	2,206.2	3,445.3

^{*}Using a 50 percent load factor and a 5-mile disposal site--1975 dollars.

Environmental impacts of synthetic fuels

One option in addressing the adverse air quality impacts associated with coal combustion is to convert the coal to a synthetic fuel through gasification or liquefaction. These synthetic fuels, however, affect the environment, because the conversion process itself includes operations that can release pollutants which have been attributable to cancer, nerve ailments, liver diseases, and fatal poisonings. The actual pollutants, their concentrations, and the extent of their adversity are currently unknown.

The following list shows some of the known or suspected pollutants associated with gasification or liquefaction processes.

Air pollutants

Particulate matter
Sulfur oxides and
other sulfur compounds
Nitrogen oxides
Hydrocarbons
Carbon monoxide
Trace metals
Hydrogen cyanide
Odors

Water pollutants

Ammonia
Cyanide
Thiocyanate
Phenols
Sulfide
Alkalinity

Some pollutants (sulfur oxides, nitrogen oxides, and carbon monoxide) can be controlled to varying degrees using existing technology; however, others such as hydrocarbons could pose a significant health hazard to plant operators and the surrounding environment, and thereby jeopardize the acceptability of the conversion processes.

To quantify the problem's magnitude, it has been estimated that a coal liquefaction plant, consuming 40,000 tons of coal daily, would produce between 4 and 30 tons of sulfur oxides, 60 and 90 tons of nitrous oxides, and 3 tons of particulates. Gasification plants are also expected to be heavy polluters. Up to 115 tons of air pollutants could be emitted for every 40,000 tons of processed coal. For every ton of coal gasified, at least 1 ton of water would be used. ^{14/} Solid waste disposal will be an additional problem to contend with.

EPA and the Energy Research and Development Administration are in the process of assessing the potential environmental impacts of the synthetic fuels processes. It is hoped that economical control technology will be developed, enabling

the gasification and liquefaction processes to be utilized. A discussion of EPA's and ERDA's research and development efforts in this regard can be found on pages 6.45 to 6.49.

MINING AND RECLAMATION

Both surface and underground mining disturb the surface, produce wastes that require disposal, affect water resources, and expose materials that produce acids when combined with air and water. ^{15/} In surface mining, the major reclamation problem is dealing with surface disruption. This normally involves smoothing out piles of overburden and attempting to revegetate the area. Comprehensive reclamation programs include restoring the surface topography, replacing the topsoil, fertilizing and revegetating, and returning the land to some productive use, whether agricultural, commercial, residential, or recreational. ^{16/} The reclamation problems associated with underground mines vary somewhat from surface mines. Reclamation efforts are directed at controlling or preventing subsidence, controlling or abating mine drainage, disposing of waste materials mined with the coal, and controlling or extinguishing coal fires.

The environmental side effects from increased coal mining, in general, can seriously affect the quality and uses of our land and water. Such impacts, furthermore, are not confined to the immediate mining site, but can be found many miles away. Some of the more serious environmental effects include acid mine drainage, land subsidence, orphaned lands, denuded lands, and soil erosion and sedimentation. Reclamation efforts are necessary during and after the mining process to prevent severe environmental damage and return the land to a productive, useful, nonpolluting, and aesthetically pleasing state.

A major problem facing policymakers is that some effects cannot be abated in an economically feasible manner. Furthermore, the internal incentives to reduce damage to surface productivity or water quality appear to be modest, given existing surface values and current reclamation costs. ^{17/} Consequently, there is some evidence that reclamation efforts fail, or have not been made, making the environmental quality a tradeoff for coal development in some areas.

The Federal Government has recently enacted legislation (P.L. 95-87) prohibiting surface mining of certain coal reserves because of potential adverse environmental impacts. This legislation is discussed in chapter 3, beginning on p. 3.17.

Environmental effects regionally

For purposes of this analysis, we segregated coal mining into three areas--Eastern, Central, and Western. Most of the environmental effects, such as soil erosion and sedimentation, are evidenced in each region. However, some impacts are unique or more significant in a particular region, because the impacts are a function of climate, topography, and the mining method.

Eastern coal region

This region is comprised largely of the area known as Appalachia extending from Pennsylvania to Alabama. The region's topography is mountainous and most of the area receives 40-50 inches of precipitation per year.

Historically, much of the Appalachian economy has been structured around mining and related activities. Both surface and underground mining methods are used for coal extraction.

The region is dotted with abandoned surface-mined lands and waste piles. This mining activity, combined with the mountainous terrain and humid conditions, has created serious environmental problems. For example, the region experiences large amounts of acid mine drainage and threats of subsidence from abandoned underground mines. In order to more fully appreciate the relative impact of the environmental problems associated with Appalachian mining, it is useful to compare the magnitude of Appalachia's problem with the rest of the United States. This can be seen in the following table. 18/

Table 5

Coal Mining Environmental Problems:

Appalachia and the United States

	Acid mine drainage (stream miles)	Subsidence area (acres)	Unreclaimed lands
Total Appalachian Region	6,300	73,730	381,180
Total United States	6,737	99,130	470,000
Appalachian (percent of total)	93.5	74.3	81.1

Acid mine drainage

Acid mine drainage is a mixture of sulfuric acid, iron, and aluminum salts which results from the oxidation of pyritic materials associated with coal and mineral deposits. The reaction produces an acidic pollutant which can damage aquatic life and often carries toxic mineral elements (lead, arsenic, and copper) which, at sufficiently high levels, can threaten humans and wildlife.

An accurate assessment of the mine drainage problem is difficult because abatement efforts are being implemented, new mine areas are being worked, and mined-out areas are being shut down. However, within the Appalachian region, the problem is considered severe, as evidenced by the table above. To further illustrate the severity in the East, measurements of stream acidity taken in northern Appalachia as compared to the Central region show a concentration variance of over 10 times--1,700 parts per million (ppm) versus 140 ppm, respectively. 19/

Land subsidence

Land subsidence is the collapse or instability of surface land resulting from the cave-in of abandoned underground mines. It is a common phenomenon in the Eastern region. Subsidence has serious implications on land use limiting the potential for building homes or other structures on the surface. In more rural areas, the subsidence threat can restrict the land's productive use for farming or grazing.

In most cases, the surface area affected by subsidence exceeds the area of the seam extracted. In central Appalachia for instance, a total of 10.6 acres is affected by the subsidence of 2 acres of coal mined by the room and pillar method. 20/

Orphan lands

Orphan lands are abandoned surface mine areas where little or no effort has been made to return mined land to a productive or natural state. Pennsylvania and West Virginia alone have some 40 percent of all unreclaimed coal mined lands in the country. These orphan lands are unsightly, contribute to erosion and sedimentation problems, and significantly limit land use alternatives. Furthermore, there are over 48,500 acres of unvegetated waste banks in the East, about 70 percent of the United States total.

Central region

The Central region for this particular analysis is an 8-State area* in the midwestern part of the country. The region has a generally flat to rolling topography, with the majority of the area receiving 32-48 inches of precipitation per year. Both surface and underground mining methods are used within this region.

The Central region has relatively small coal mining-related environmental problems compared to the East. Erosion, acid mine drainage, and siltation problems are somewhat ameliorated by the relatively level terrain. Furthermore, precipitation is sufficient to support vegetation after mining. However, there is one environmental consequence from mining which can be considered a major problem in this region--that is denuded lands.

Denuded lands

Mining causes a chemical and physical decomposition of the soil which restricts land utilization for agriculture and may affect the land's capability to support any vegetation whatsoever. Consequently, land which once was productive cropland can become a partially denuded wasteland until the nutrient consistency of the soil is restored. Current figures indicate that, nationally, about 70,000 acres are annually being affected by surface coal mining. The Central region (plus the States of Ohio, Nebraska, and Michigan) account for nearly 41,000 acres of that total. 21/ Much of the land disrupted during surface mining in the Central region is classified as prime agricultural land. BOM has estimated that many of these acres will remain underutilized due to mining operations and the loss of soil consistency.

Western region

Western coal reserves underlie 128 million acres of lands located in areas of diverse climate and terrain such as the Northern Great Plains, the Rocky Mountains, and the Southwest Deserts. The average annual precipitation, for instance, ranges from 24 inches in the plains to less than 8 inches in the arid desert areas. The topography changes from the

*This area includes the States of Arkansas, Illinois, Indiana, Iowa, Kansas, Missouri, Oklahoma, and western Kentucky.

jagged mountains of the Rockies to the gently rolling hills of the plains. This region has two serious environmental problems--disruption of the hydrology and revegetation.

Hydrology

Many strippable coal beds in the West are near or underlie surface drainage channels and underground waterways of permeable rock called aquifers. Underground and surface mining of this coal could cause serious impacts, significantly disrupting the West's fragile hydrologic system and causing serious secondary effects.

During surface mining, for instance, natural drainage channels are often diverted to facilitate coal extraction. Diversion channels are usually constructed of easily erodible soil and, during heavy rains, streams and waterways are often polluted by their erosion, affecting both plant life and fish life. In addition, underground mining can contaminate (through saline solutions and other minerals) usable aquifers which support human, animal, and plant life. In many cases, there is seldom an alternate source of water, thereby significantly reducing the already limited ground water supply.

Of special interest in the West is the preservation of alluvial valley floors--downstream valleys fed by surface or near surface streams. These valleys are the productive lands for agriculture and cattle ranching in the West. Mining in or near these areas can disrupt drainage patterns, causing a loss of recharge to the alluvial floors and reducing the valley's productivity. The recent surface mining legislation will protect these valleys. (See p. 3.17.)

Denuded land

Established methods for rehabilitating and revegetating mined areas in humid environments are not directly transferable to the more arid Western region. Therefore, surface mining in this region can produce the temporary or permanent degradation of large land areas.

The potential for rehabilitating any surface-mined area in the West is critically site-specific. The proper application of proven technologies is particularly crucial if rehabilitation efforts are to be successful. Revegetation of many areas can only be accomplished with good management and major sustained inputs of water and fertilizer. And in the case of drier areas of the West, even these efforts may

not reclaim the land. The National Academy of Sciences, for instance, has concluded that in desert areas with ten inches or less of precipitation, permanent revegetation may be impossible. The only reclamation feasible in these areas may be to restore hydrologic conditions and minimize erosion allowing natural rehabilitation to take place, but this may take more time than is acceptable to society. 22/

ECONOMIC IMPACT OF RECLAMATION PRACTICES

There is a cost associated with mining reclamation practices. It differs from region to region because the costs and efforts necessary are a function of the mining method, terrain, and climate.

A 1975 BOM survey of reclamation costs at 31 surface mine sites provided the basis from which we calculated the costs per ton and costs per acre of land disturbed. The following table shows these costs by region and for each reclamation cost category. See chapter 3 for a discussion of the cost of restoring mined areas to the original contour of the terrain.

Table 6

Surface Mine Reclamation Costs

	East (15 sites)		Central (9 sites)		West (7 sites) (note a)	
	Cost per acre (note b)					
	<u>Percent</u>		<u>Percent</u>		<u>Percent</u>	
Premining engineering/ anti-pollution	\$ 233	2.96	\$ 710	14.55	\$ 555	19.79
Permits and fees	46	.58	30	.61	35	1.25
Topsoil/over-burden handling	7,324	92.98	4,048	82.93	2,043	72.81
Revegetation	<u>274</u>	<u>3.48</u>	<u>93</u>	<u>1.91</u>	<u>173</u>	<u>6.16</u>
	<u>\$7,877</u>	<u>100.00</u>	<u>\$4,881</u>	<u>100.00</u>	<u>\$2,806</u>	<u>100.00</u>

	Cost per ton					
	<u>Percent</u>		<u>Percent</u>		<u>Percent</u>	
Premining engineering/ anti-pollution	\$ -	-	\$.14	15.73	\$.04	25.00
Permits and fees	.01	.35	-	-	-	-
Topsoil/over-burden handling	2.78	95.53	.73	82.02	.12	75.00
Revegetation	<u>.12</u>	<u>4.12</u>	<u>.02</u>	<u>2.25</u>	<u>-</u>	<u>-</u>
	<u>\$2.91</u>	<u>100.00</u>	<u>\$.89</u>	<u>100.00</u>	<u>\$.16</u>	<u>100.00</u>

a/The western sites do not include irrigation costs in the revegetation estimate. One researcher estimated that this could increase the cost per acre by about \$500.

b/The per-acre cost figures and the per-ton cost figures are not in direct proportions due to variances in coal seam thickness of the sample sites. Those categories showing less than \$.01 have not been included in the totals because they would not affect the totals when rounded.

For underground mining the two primary environmental effects to which cost factors can be related are subsidence and acid mine drainage. The following table shows the cost estimates for these abatement practices:

Table 7

Underground Mine Reclamation Costs

	<u>Cost per ton</u> <u>(note a)</u>	
	<u>Range</u>	<u>Average</u>
Subsidence <u>23/</u>	\$1.00-5.00	\$1.50
Acid mine drainage <u>24/</u>	None cited	.0587

a/These costs represent those borne by society to abate past damage primarily through demonstration projects. Due to technological limitations, coal producers are usually not required to incur these costs. Current legislation will most likely change this situation.

Cost to abate future
environmental impacts

To estimate possible future environmental impacts, we used the coal projections included in BOM and Edison Electric Institute energy scenarios. For comparison, we used a coal supply level based on industry estimates of planned capacity additions through 1985 as a middle of the road case. Note that the BOM projection is in the approximate range of the level recommended in President Carter's National Energy Plan. The following table presents the production levels of the three scenarios broken down by region and by method of mining:

Table 8
Regional Distribution of Coal
Production Under Selected Scenarios

	<u>1985</u>			<u>2000</u>	
	<u>BOM</u>	<u>Industry planned capacity</u>	<u>EEI</u>	<u>BOM</u>	<u>EEI</u>
	----- (million tons) -----				
<u>Surface</u>					
Eastern	132.58	133.55	126.53	212.91	126.30
Central	88.78	87.48	82.92	141.31	84.43
Western	357.55	281.96	267.30	574.35	340.70
Total surface	578.91	502.99	476.75	928.57	551.43
<u>Underground</u>					
Eastern	295.42	222.69	211.12	474.65	281.58
Central	72.58	68.17	64.65	116.06	69.17
Western	41.71	27.92	26.49	67.00	39.76
Total underground	409.71	318.78	302.26	657.71	390.51
Total coal production	988.62	821.77	779.01	1,586.28	941.94

Note: These figures differ somewhat from those in chapter 4 because in this analysis, Kentucky was divided into eastern and western.

We then took these production levels and related them to the reclamation costs presented earlier and calculated the following annual cost to reclaim surface-mined land, prevent subsidence, and treat acid mine drainage:*

*Acid mine drainage occurs, for the most part, only in the East, and will only be applied to coal produced from eastern underground mines.

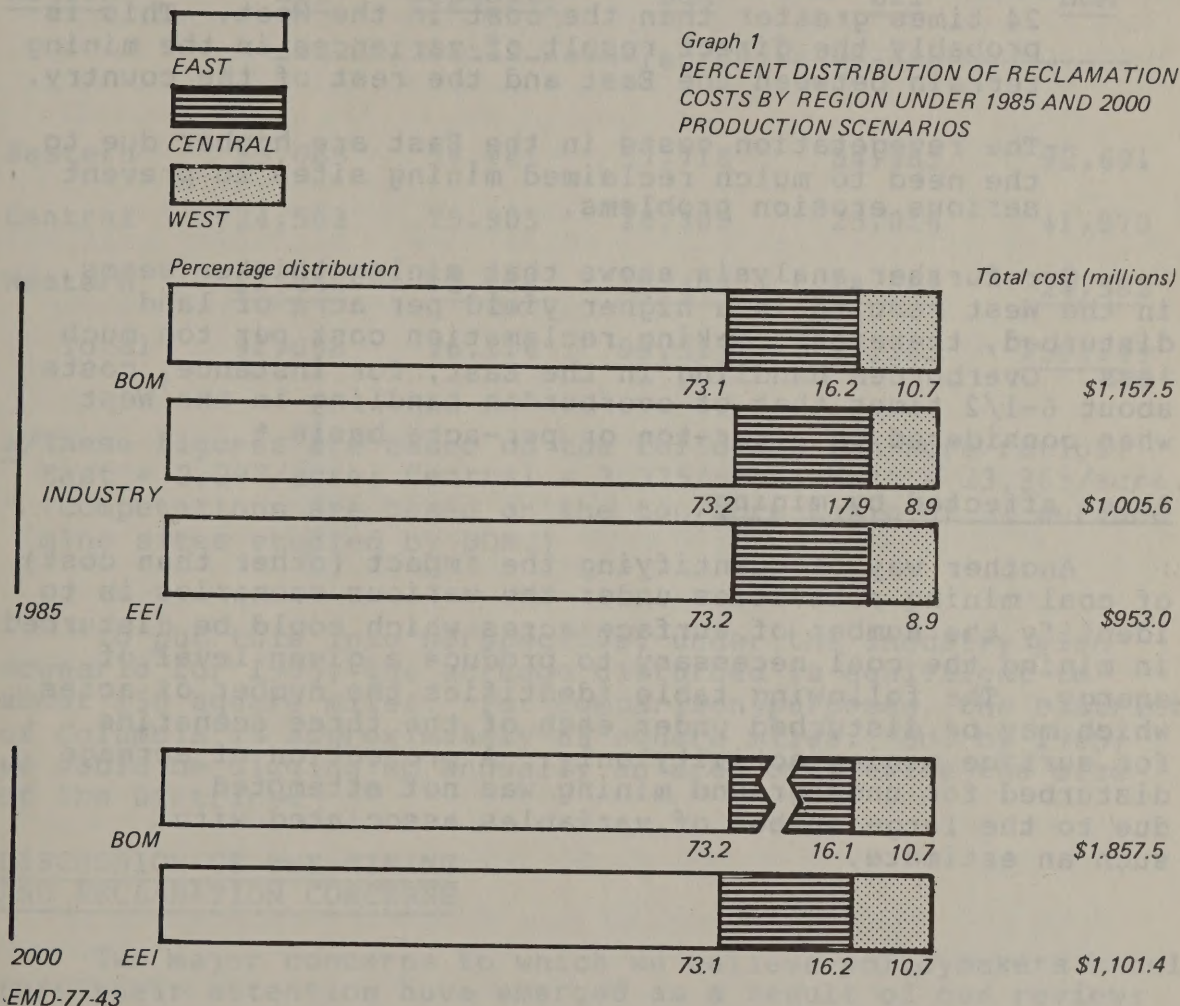
Table 9

Cost to Abate Environmental Impact
of Coal Mining in 1985 and 2000 Under Various

		<u>Production Scenarios</u>				
		<u>1985</u>			<u>2000</u>	
	<u>Cost factor</u>	<u>BOM</u>	<u>Industry</u>	<u>EEI</u>	<u>BOM</u>	<u>EEI</u>
	<u>(\$/ton)</u>		<u>planned</u>			
			<u>capacity</u>			
----- (millions) -----						
<u>Surface reclamation</u>						
Eastern	\$2.91	\$385.8	\$388.6	\$368.2	\$619.6	\$376.5
Central	.89	79.0	77.9	73.8	125.8	75.1
Western	.16	60.8	47.9	45.4	97.6	57.9
Total surface reclamation cost		<u>\$525.6</u>	<u>\$514.4</u>	<u>\$487.4</u>	<u>\$843.0</u>	<u>\$500.9</u>
<u>Underground Mining</u>						
<u>Reclamation</u>						
<u>Subsidence</u>						
Eastern	1.50	\$443.1	\$334.0	\$316.6	\$712.0	\$421.1
Central	1.50	108.9	102.2	96.9	174.1	103.7
Western	1.50	62.6	41.9	39.7	100.5	59.6
Subtotal subsidence control costs		<u>\$614.6</u>	<u>\$478.1</u>	<u>\$453.2</u>	<u>\$986.6</u>	<u>\$584.4</u>
<u>Acid mine drainage (note a)</u>						
Eastern	.06	17.3	13.1	12.4	27.9	16.5
Total underground mining reclamation costs		<u>\$631.9</u>	<u>\$491.2</u>	<u>\$465.6</u>	<u>\$1,014.5</u>	<u>\$600.9</u>
Total abatement cost		\$1,157.5	\$1,005.6	\$953.0	\$1,857.5	\$1,101.4

a/It should be recognized that acid mine drainage control costs do not supply permanent solutions but must be continued for several decades after the initial extraction. Thus, these figures can be conservative.

An analysis of these costs by region for each scenario is summarized in graph 1:



The regional comparison shows that, in all cases, the Eastern region accounts for about 73 percent of the total costs because:

- Almost 44 percent of the expected coal production is in the East.
- The cost per ton of handling topsoil and overburden, which is 95 percent of the cost in the East, is better than four times that in the Central region, and about 24 times greater than the cost in the West. This is probably the direct result of variances in the mining terrain between the East and the rest of the country.
- The revegetation costs in the East are higher due to the need to mulch reclaimed mining sites to prevent serious erosion problems.

Our further analysis shows that mining thicker seams in the West results in a higher yield per acre of land disturbed, therefore, making reclamation cost per ton much less. Overburden handling in the East, for instance, costs about 6-1/2 times that of overburden handling in the West when considered on a per-ton or per-acre basis.*

Acres affected by mining

Another way of quantifying the impact (other than cost) of coal mining activities under the various scenarios is to identify the number of surface acres which could be disturbed in mining the coal necessary to produce a given level of energy. The following table identifies the number of acres which may be disturbed under each of the three scenarios for surface mining activity only. A projection of acreage disturbed for underground mining was not attempted due to the large number of variables associated with such an estimate.

*Some of this cost variance can be attributed to the topographical characteristic differences, but much of it is due to the seam thickness variances.

Table 10

Estimate of Acres Disturbed Annually

During Surface Mining (note a)

<u>Region</u>	<u>EEI</u>	1985	<u>BOM</u>	2000	
		Industry planned capacity		<u>EEI</u>	<u>BOM</u>
----- (acres) -----					
Eastern	55,085	58,141	57,718	54,985	92,691
Central	24,563	25,905	26,305	25,016	41,870
Western	<u>11,440</u>	<u>12,068</u>	<u>15,303</u>	<u>14,582</u>	<u>24,582</u>
Total	<u>91,088</u>	<u>96,114</u>	<u>99,327</u>	<u>94,583</u>	<u>159,143</u>

a/These figures are based on the following ton/acre ratios:
 East = 2,297/acre; Central = 3,375/acre; West = 23,365/acre.
 (Computations are based on the ton/acre ratio of 31 surface
 mine sites studied by BOM.)

To put this into perspective, under the industry plan scenario for 1985, the acreage disturbed is equivalent to about 150 square miles. For comparison purposes, the District of Columbia is approximately 68 square miles. So, by 1985, we would be digging up annually an area over twice the size of the District.

DISCUSSION OF THE MINING
AND RECLAMATION CONCERNS

Two major concerns to which we believe policymakers should turn their attention have emerged as a result of our review:

--The environmental consequences of coal extraction and the degree to which these will become the tradeoff for coal development.

--The effect of mining reclamation laws on coal production.

Environmental consequences of coal mining

Many environmental consequences can be minimized with careful planning and current technology. For example, proper contouring with planned drainage patterns can minimize erosion and sedimentation from waste piles and mine sites. Denuded and orphan lands can be mulched and fertilized until revegetation is established. (Burying toxic materials under topsoil increases revegetation success.) The problem, however, is that current technology and planning cannot economically abate all impacts of mining, specifically acid mine drainage, land subsidence, denuded lands, and hydrologic disturbances.

Acid drainage

According to EPA, acid drainage is the most serious pollutant arising from mining activities. Utilizing available technology, acid drainage could be treated or abated; but the cost has proved uneconomical and, therefore, the techniques are not widely practiced.

Acidic pollutants are generated from both surface and underground mining. This problem is continually perpetuated by acidic runoff from abandoned mine lands and unreclaimed waste piles. Increased coal mining activities to meet future energy demands will continue to aggravate the problem. Sealing underground mines or treating polluted streams to neutralize the acid are two of the available abatement practices. The financial commitment necessary to implement these practices, however, is enormous. For example, a single plant on Pennsylvania's Rausch Creek neutralizes acid drainage from 18 abandoned and 25 active underground and surface mines. The plant can treat up to 32 million gallons of acid water per day and has cleaned a reported 28 miles of streams. The treatment plant was constructed at a cost of \$2.5 million ^{25/} and has an annual operating cost of \$167,000.

In 1970 the Department of the Interior estimated that it could cost as much as \$6.6 billion to clean up all the existing acid mine drainage in the Nation. ^{26/} In addition, under increased coal development, more waterways would be polluted by acid drainage, which would lead to additional abatement costs.

Land subsidence

Land subsidence is a serious consequence of underground mining and, although technology has been developed to control subsidence, the methods are generally costly and not practiced other than through demonstration projects.

Control methods include providing additional roof support with grout columns,* or backfilling mine shafts with mine waste, fly ash, or sand and gravel. The mining method can also influence the subsidence potential, although it is not considered a control methodology. For instance, room-and-pillar mining leaves columns of coal to serve as roof supports, but deterioration of these natural pillars leads to failure and eventual surface subsidence.

Estimates of subsidence control methodology costs are at best tentative. For perspective purposes, however, GAO utilized the cost factors of about \$34,000 per acre for backfilling and \$75,000 per acre for grout columns. 27/ Utilizing these estimates to stabilize the acres already affected by subsidence, the Nation would expend between \$3.4 and \$7.4 billion.

Denuded land

Surface mining in the arid regions of the West can result in a large area of land becoming denuded for a long period of time. In some areas, in fact, vegetation can never be restored. Although current reclamation techniques can succeed in humid areas, the practices are unacceptable in more arid regions. In desert areas, for instance, the only reclamation potential will be to restore the original hydrologic conditions and minimize the offsite effects of erosion. Rehabilitation of some sites may occur naturally, but probably on a time scale unacceptable to society because it may take decades, or even centuries, for these areas to reach stable conditions. 28/

Current revegetation research addressing this situation is meeting with good success. However, it is only in the experimental stages with many questions still unanswered. Commercial application, therefore, is a long way off, leaving an ever increasing amount of land to remain barren and scarred.

The projected cost to implement any of these research methods will be high. In Montana, for example, the cost to revegetate one project area totaled about \$711 per acre, 29/ or about four times the average cost to revegetate an acre of land in the West. (See Table 6, p. 6.29) In addition, the undefinable social costs of the land which

*Grout columns are constructed from the surface by drilling holes from the surface to the mined cavity and pouring in a mixture of cement and fly ash or gravel to fill partial spaces of the abandoned mine.

can never be restored must be considered in determining the consequences of this problem.

Hydrologic imbalances

Surface mining operations in the West (especially the arid and semiarid areas) can have a significant impact on the hydrologic balance* of the mined area and its environs. The total extent and severity of these impacts are unknown; however, a few documented cases illustrate the consequences of the primary and secondary (occurring many miles away) effects of such an imbalance.

The hydrologic balance of an area is a complex relationship maintained by a number of factors, including flow patterns of aquifers, quantities of surface water, and the erosion, transport, and disposition of sediments. The impacts of mining on any of these factors can trigger serious consequences throughout the system. Although mining in arid and semiarid areas of the West has not existed long enough to allow full analysis of the hydrologic consequences of such activities, some studies have demonstrated the potential severity.

For example, in one documented case,

"The destruction of vegetation in part of an alluvial valley triggered substantial erosion leading to the deepening of stream channels. This lowered the ground water levels of adjacent alluvial valley floors which in turn resulted in additional vegetation loss. As erosion increased in the newly denuded lands, the cycle worsened. Eventually the entire alluvial floor was affected by reducing the amount of and changing the nature of the vegetation which was essential to the local economy as well as the long-term productivity and stabilization of the land." 30/

While this may be an extreme example of the consequences associated with surface mining in the West, similar disasters could result from any expansion of mining in highly vulnerable areas. The primary drawback in preventing such occurrences, however, is that there is little consensus on which land areas are, in fact, vulnerable. This stems from a lack of knowledge and data on what constitutes an aquifer or an alluvial valley

*The hydrologic balance is the equilibrium established between the ground and surface water of an area and between the recharge and discharge of water to and from that system.

floor. Consequently, the leasing and mining continues in areas in or adjacent to known alluvial areas. The full impact of this situation may not be evident for many years, but it is certain that any impact will be long term and costly to reconcile, even if reclamation is possible.

Given the specific level of coal development that may be necessary to meet energy needs, the Nation must decide to what degree these environmental consequences will become a tradeoff to that development.

Mining reclamation laws

Until recently, the only Federal control over mining reclamation applied to mining of coal on federally owned lands through DOI regulations. In July 1977, the Surface Mining Control and Reclamation Act was passed (P.L. 95-87), establishing a nationwide program for protection from the adverse effects of surface coal mining.

In 1974 and again in 1975, the Congress passed bills on regulating the surface mining of coal; both were vetoed by the President. Federal legislation proposed in 1976 (H.R. 9725) was tabled by the House Rules Committee. Provisions of this bill were designed to set minimum reclamation standards and provide environmental protection omitted in regulations applicable to Federal lands and various States' laws. For instance the bill provided

- special reclamation standards for mining areas that are difficult to reclaim, that is, alluvial valley floors and steep slopes;
- requirements to regrade to approximate original contour and bury toxic substances;
- funds for reclaiming orphan lands; and
- some control on the surface effects of underground mining.

In vetoing earlier reclamation bills, the previous administration cited several unfavorable results of a Federal law. Reclamation standards for alluvial valley floors and steep slopes, for instance, were cited as potentially reducing mineable coal resources. It was also argued that small mine operators would not be able to fully comply with the law's provisions, resulting in further reductions in coal supply and increasing unemployment within the industry. In the final analysis, the administration claimed the proposed surface mining controls would reduce production in the short run,

raise coal prices and higher utility bills, and increase reliance on foreign crude oil.

The new mining reclamation legislation recently passed in the 95th Congress incorporates many of the environmental protection provisions of the 1976 legislation. In addition, P.L. 95-87 makes the States primarily responsible for developing, issuing, and enforcing mining and reclamation regulations which are (at the very least) consistent with federally established minimum standards. A federally established program will be implemented in instances in which a State fails to comply with the "State program" requirements. Furthermore, the act provides for the designation of areas which are deemed unsuitable for surface coal mining activity (that is, aquifer lands, prime agriculture land, etc.). Also off-limits to surface mining because of the potential adverse environmental effects are: alluvial valley floors, steep slopes, and certain lands where surface owners rights are protected.

Proponents of Federal strip mine legislation contended it would provide more technically sound reclamation and better protection of the environment than a system of individual State laws. It is argued that States are disinclined to impose thorough reclamation standards because this puts local business at a competitive disadvantage and Federal legislation will be more consistently enforced and subject to less political pressure.

Generally, States favor the development of coal within their boundaries but want to control the rate of development --including the level of reclamation required. Thirty-four States currently have some form of reclamation law. Some of them are sophisticated and technical with detailed requirements, such as segregation of topsoil and regrading to certain specifications. Other States have strict laws but do not have the staffs or funds to adequately enforce them. Still other States have laws requiring only minimum reclamation standards to be met. In some instances, this laxity results from the State's desire to stimulate or encourage industrial development.

AVAILABILITY OF WATER FOR ENERGY DEVELOPMENT

Water supply problems are more regional than national. 31/ In certain parts of the West, for instance, water is either in short supply or is already fully allocated, though not necessarily fully utilized. State and Federal laws, interstate compacts, international treaties, and Indian treaties govern water availability. In some areas, additional uses or diversion of water, such as with increased energy development, will almost certainly mean a sacrifice of an existing usage or an environmental effect leading to a social cost.

Major coal deposits in the West are located in several water resource regions as defined by the Water Resources Council. As discussed below, the supply of water and commitments for water use vary among regions and within a single region.

The Missouri region encompasses areas of large coal deposits in Montana, most of Wyoming, and eastern Colorado. Water availability varies considerably, both seasonally and over time; droughts occur periodically. Ground-water availability and water quality are also subject to variation.

This region has potential hydroelectric sites which may be developed. There also exist potential sites for coal-fired electric generating plants.

Major problems can be expected in this region. Water rights for energy must be established with due consideration for environmental consequences. In some areas competition for water is expected to be intense. Facilities are required to move water to the coal or the coal to the water. Careful planning and development will be required to protect the environment.

The upper Colorado region includes areas of western Wyoming and Colorado, eastern Utah, and northern New Mexico, which contain large bituminous and subbituminous coal deposits as well as petroleum, natural gas, and oil shale resources. There are also plans to expand coal-fired electric generation in this region.

Most available surface waters are committed to local uses, downstream delivery and transmountain transfer. Stream flows fluctuate widely in time and space. The quality of the surface water is generally very good, although it decreases in the lower regions. Ground-water quality varies considerably and is generally not as good as that of the surface waters.

The availability of water for use is limited by physical conditions, institutional regulations, economic considerations, and environmental and social impacts. Although thermal pollution has been minor to date, it is expected to increase.

The major problem is limited water supply in an area of major energy resources. The water rights granted by the States in some streams of the region exceed the water available during low flow periods.

The lower Colorado region encompasses Arizona and western New Mexico. The region has significant coal deposits, and plans are being made for a steam-electric generating plant.

The Colorado River compact obligates the upper Colorado region not to deplete the flow entering the lower Colorado region below an aggregate of 75 million acre-feet over any 10-year period. Of the average annual amount of 7.5 million acre-feet, the California region has a priority to 4.4 million acre-feet. In addition, there is some precipitation as well as ground-water to augment supplies. Water quality in this region is generally not as good as in other parts of the Nation.

Without additional water imports, ground-water overdraft (pumping out more water than is replenished naturally) will continue. Increasing the water supply without increasing the ground-water overdraft is a major problem in this area.

Use of water for energy development

The largest water withdrawals in the United States are for cooling purposes in electric generating plants. The current most widely used system--which can be referred to as a once-through system--returns the water to the rivers. Other systems that use less water have been proposed. Some of these alternative systems are cooling ponds and dry and wet-dry systems. Water will also be consumed in the processes for converting coal to gas or liquid fuels. The following table shows the water needs for various energy processes. ^{32/} The wide range of numbers in the water requirement column reflects a variety of available practices.

Table 11

Water Needs for Various Energy Processes

<u>Energy system</u>	<u>Water needs</u>
Steam-electric nuclear	
Evaporative cooling	17,000 acre-ft/yr/1,000MW unit
Pond	12,000 acre-ft/yr/1,000MW unit
River	4,000 acre-ft/yr/1,000MW unit
Wet-dry radiator	2,000 acre-ft/yr/1,000MW unit
Steam-electric coal	
Evaporative cooling	15,000 acre-ft/yr/1,000MW unit
Pond	10,000 acre-ft/yr/1,000MW unit
River	3,600 acre-ft/yr/1,000MW unit
Dry radiator	2,000 acre-ft/yr/1,000MW unit
Geothermal	48,000 acre-ft/yr/1,000MW unit
Natural gas	50,000 acre-ft/yr throughout the West
Crude oil	50,000 acre-ft/yr throughout the West
Refineries	39 gal./barrel/crude
Oil shale	7,600 to 18,900 acre-ft/yr/100,000 bpd plant
Coal gasification	10,000 to 45,000 acre-ft/yr/250 million standard cubic feet/day plant
Coal liquefaction	20,000 to 130,000 acre-ft/yr/100,000 bpd plant
Coal slurry pipeline	20,000 acre-ft/25 million tons coal
Coal mining	
vegetation re-establishment	.5 to 4 acre-ft/acre/yr (some areas may require 2 years)

Although the table shows water needs of various energy processes, in some processes the water is returned to streams and can be reused for industrial, agricultural, and municipal treatment. Therefore, it is informative to consider the consumptive water requirements for various processes. The following table sets out the water requirements of several energy processes per million Btus. 33/

Table 12
Water Consumption Requirements
For Selected Energy Processes

<u>Energy source</u>	<u>Consumptive water requirement</u>
Steam-electric-nuclear	200 to 2,000 lbs. water/million Btus
Steam-electric-coal	200 to 1,350 lbs. water/million Btus
Coal gasification	800 to 1,350 lbs. water/million Btus
Oil shale	100 to 240 lbs. water/million Btus
Coal slurry pipeline	0 to 110 lbs. water/million Btus

The water needs of energy processes, presented above, suggest that western water resources would be better conserved by shipping a coal slurry out of the region than by shipping out electrical power or synthetic gas. However, from a water standpoint the shipping of coal by conventional means of transportation (for example, rail, barge, etc.) which do not normally have a consumptive water requirement, is more attractive than the slurry pipeline.

Competition for water rights may increase water prices but probably would have an insignificant effect on the amount of water used for energy production. The dollar return for water used for energy production is undoubtedly much higher than it is in many other uses, such as agricultural irrigation. Therefore, market effects may divert water from agricultural and industrial use to energy production.

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The primary control mechanisms for water use in the West are with water rights and other agreements for water allocation and not necessarily water supply. International treaties with Canada and Mexico control streams flowing across U.S. boundaries. Additionally, the Congress has approved numerous interstate compacts on interstate streams. The waters are generally apportioned among the States and each State is then left to allocate its share of the water among intrastate users.

Indian water rights stem from treaties and agreements approved by the Congress or executive orders. These claims have water right priority as of the date the reservation was established and maintain their validity even though unexercised. In addition, State and Federal regulations further control and even restrict water use in Western States. All these agreements and allocations deplete the water supply "on paper," though they are not necessarily physically depleted.

In any event, water for additional uses, such as energy development, may not be available. As western coal deposits are developed, an increasing demand will be placed on water resources for coal conversion and generation of electricity. Potentially, this demand for water may not be met in the West because of reluctance to convert water rights from existing uses and coal may have to be shipped to other geographic areas where water is more plentiful.

ENVIRONMENTAL CONTROL RESEARCH AND DEVELOPMENT

Expanding the use of coal as an energy supply source (with its resulting adverse environmental impacts) is not an either/or proposition, because the adverse impacts may be mitigated through good management and continued research and development. A discussion of the Federal Government's efforts to develop environmental control technology follows.

Seventeen Federal departments and agencies conduct energy related environmental research under the auspices of the Interagency Energy/Environment Research and Development Program. The Interagency Program, which is planned and coordinated by EPA, is a 5-year effort begun in fiscal year 1975 to stimulate the development of domestic energy resources by providing both the environmental data and control technologies necessary to safeguard human health and welfare.

Environmental control technology research is conducted in three areas: coal extraction and preparation, direct burning, and coal conversion. The research is carried out primarily by three Federal agencies--EPA, BOM, and ERDA. However, the Department of Agriculture and the Tennessee Valley Authority (TVA) also perform control technology research. The objectives of this research are to develop techniques or technology that will allow coal to be mined, converted, and burned without serious environmental impacts.

Research is being done on controlling coal combustion's harmful atmospheric emissions. Although further improvement is desirable, methods are currently available for controlling sulfur oxides and nitrogen oxides emissions. However, control technology is not currently available for trace elements and for fine particulates that are less than 1 micron in size. In addition, the process of converting coal to synthetic fuel gives off certain emissions which may be harmful. Little is known about the environmental consequences of conversion processes, but research is currently underway to assess the emissions from these processes and develop control technology.

Research into controlling the environmental effects of coal mining addresses the problem areas of land subsidence, acid mine drainage, and land reclamation. There are methods of treating acid mine drainage and controlling land subsidence in abandoned mines; however, the cost of treatment is high. Due to the high cost, the current research effort is directed to prevention of acid mine drainage and land subsidence.

Most mined lands can be reclaimed with current technology. However, some lands in arid and semiarid regions like those in the West are not currently reclaimable, and it is on those lands that research is concentrated. In addition, research is being done to improve reclamation methods and reduce the cost of all land reclamation. If the low-sulfur coal deposits of the Western United States are to be developed, it is essential that adequate land reclamation techniques be developed. Further, since increased coal production means opening more mines, it is essential that methods for preventing acid mine drainage and land subsidence be developed.

Coal extraction and preparation

Research in the extraction program addresses potential problems and control methods for underground and surface coal mining. The overall objectives of Federal research efforts in this area are to provide data and analysis to assure that coal mining operations, surface and underground, can be conducted with adequate land and water protection. Underground mining research specifically addresses methods of controlling or preventing acid mine drainage and land subsidence, and disposing of mine waste. Surface mining research addresses techniques for returning mined lands to a usable form and reducing adverse environmental impacts on affected land and water resources.

The products from this research will be instruction manuals which delineate the problems and provide control methods, technical handbooks on vegetation of surface-mined lands and spoils in the Eastern and Western coal mining regions, and improved mining equipment and techniques. The manuals and handbooks should be available for use by the coal industry and other related groups in the early 1980s.

The primary objective of coal preparation research is to develop commercially available processes for reducing ash, sulfur, and potentially hazardous trace elements from coal prior to combustion. Coal cleaning results in a less polluting and more efficient fuel. Research in this area is being conducted by EPA, ERDA, and BOM. These research

efforts involve evaluating current coal cleaning technology and developing advanced technologies for cleaning coal. Methods being evaluated or developed include

- conventional ash removal methods to remove pyritic sulfur;
- advanced coal cleaning methods; and
- chemical cleaning methods involving leaching, hydrogenation, acid, or caustic treatment.

EPA estimates these types of coal cleaning technologies may be available to industry by the end of 1981.

Direct burning

Developing technology which will control the pollutants released in coal combustion may permit expanded use of coal.

The technology to remove sulfur dioxide after combustion is called flue gas desulfurization (FGD). This removal process can be divided into two major categories--nonregenerable and regenerable.* FGD systems which reduce sulfur oxides emissions to acceptable levels are commercially available, but reliability problems and high maintenance costs have restricted widespread application. EPA's research efforts in this area are directed toward upgrading operating performance and reliability, minimizing maintenance costs, developing second generation regenerative FGD systems, improving waste product disposal techniques, and improving byproduct recovery techniques.

TVA, BOM, and ERDA also sponsor flue gas cleaning research projects. EPA is currently estimating that the final report on the FGD control technology development program will be completed by 1979.

*In a nonregenerable FGD system, an agent (lime or limestone) combines chemically with the sulfur oxides from the flue gas, and the resulting product is then removed from the system and discarded. The discarded product presents waste and water pollution problems, and the proper disposal of the residue is very important. In a regenerable system, the waste disposal is a lesser problem because after the sulfur oxides are removed from the flue gas, the agent (metal carbonates or magnesium oxide) and sulfur are recovered for reuse.

Nitrogen oxides emissions from coal combustion can be generally controlled by either modifying the combustion system or by employing flue gas denitrification technologies. EPA's research efforts are directed toward developing both of these controls. EPA's analysis has shown that the combustion modification approach can meet current nitrogen oxides emission standards. The program builds on the existing techniques, while also generating new technology. The research efforts range from minor hardware changes on existing boilers for near-term control technology to complete combustion system redesign. EPA estimates that the technology for combustion modification will be accomplished in the 1980-1985 time frame.

EPA is also researching flue gas treatment techniques for removing nitrogen oxides. This effort is relatively new. A 1969 study concluded that combustion modification and not flue gas treatment offered the most promising control approach.

Fine particulates pose a health hazard as already noted. When these particulates combine with trace elements, the health hazards are compounded. (See p. 6.15 for effects.) Technology exists to remove most fine particulates but 1 to 2 percent usually escape into the atmosphere. They are usually less than 1 micron in size and are thought to be the most harmful. EPA's control research program is seeking remedies for deficiencies in existing control equipment, and advances in removal technology. EPA currently predicts research will be completed in 1978.

EPA does not currently have a control technology program specifically for trace elements, but the Agency contends that the technologies for sulfur oxides, nitrogen oxides, and particulates will remove and control some trace elements. EPA is assessing trace elements as part of its Combustion Pollutant Assessment Program and will develop control technology.

Coal conversion

Synthetic fuel processes are being developed to convert coal to clean burning gas or oil. These conversion processes themselves, however, include various operations which would release hazardous particulates and hydrocarbons into the air and hazardous chemicals into water supplies. The actual detriment to the environment, if any, of the conversion processes is not known.

EPA has the primary responsibility for assessing the environmental factors of energy technology and for developing controls to protect the environment from adverse effects.

EPA and ERDA have research and development programs which seek to insure an environmentally sound synthetic fuels industry. These research efforts have two objectives--to determine the potential environmental impacts of synthetic fuel processing operations and to develop control technology to minimize the negative aspects of these impacts. EPA programs underway in this area are:

- Evaluating the environmental problems associated with conversion of fossil fuels into synthetic fuels, using an approach that will characterize all potential pollutants which would be generated during synthetic fuels development.
- Developing and demonstrating technology to control pollutants resulting from synthetic fuel development.

ERDA's research efforts are directed to defining problems and quantifying environmental effects of both existing coal conversion processes and those under development. ERDA's research efforts are:

- Classifying processes in terms of all pollutants generated.
- Surveying coal processing programs funded by ERDA to assess environmental studies planned and needed.
- Surveying available pollution control technology from existing and planned pilot plants. (Controls in related industries are being considered for adaptation to coal processes.)
- Developing test programs for analysis of pollutants from each synthetic fuel process.
- Selecting, installing, and observing pollutant monitoring instruments.

As stated earlier, the environmental effects of coal conversion processes are unknown, and it is important for these effects to be identified and proper control techniques developed before coal conversion processes are commercialized. Several of the second generation conversion technologies will be demonstrated on a relatively large scale in the next 5 years.

SUMMARY

Of all the costs associated with increased coal production and consumption, the nonmonetary ones are perhaps the most important--the degradation of the environment and the social changes that will occur in some areas. Social changes are discussed in chapter 7.

The amount of pollutants emitted during coal combustion can be enormous. Current Federal and State regulations seek to control certain coal pollutants--sulfur oxides, nitrogen oxides, and particulate matter. This effort is costly. Under the BOM scenario, GAO estimated the cumulative capital costs for emissions control to be about \$19.1 billion in 1985 and \$26.4 billion by the year 2000. Under an industry scenario, these costs will amount to about \$15.9 billion by 1985. Consequently, the average residential consumer's electric bill could increase by 9 to 10 percent in 1985 under these projections.

In addition, disposing of the sludge collected in pollution control devices such as scrubbers will be costly. To put this sludge problem into perspective, the pollution control waste material generated annually under the industry scenario in 1985 is equal to the municipal waste generated in the United States during the course of one year.

Despite the costs, there are certain coal emissions which are not currently regulated.

First, the particulate control technology in use today is only partially effective in preventing fine particulates (1 micron or smaller) from escaping into the air. These fine particulates are alleged to pose a special health hazard because of their ability to penetrate the respiratory system.

Second, the current regulations do not control other pollutants which are considered dangerous to human health. In particular, there are no controls on the emission of trace elements emitted in coal combustion such as mercury, lead, beryllium, arsenic, fluorine, cadmium, and selenium.

Moreover, the majority of the acidic sulfate pollution is attributed to coal combustion. Control of sulfates in the atmosphere may not depend solely on the control of sulfur dioxide, but on control of precursors such as fine particulates and nitrogen oxides. EPA projects the sulfate levels in 1990 to be similar to the 1975 level--a level which may cause serious health problems as well as acid rains which harm plant and animal life.

Another coal pollutant which is not controlled is carbon dioxide. This carbon dioxide build-up could cause global changes in the weather. With continued growth in the use of fossil fuels, the effect of coal combustion on climatic conditions may become an important problem during the next 50 years.

The chief environmental problems of coal production include acid mine drainage, land subsidence, denuded lands, soil erosion, and sedimentation. A major problem facing policymakers is that some of these effects cannot be abated in an economically feasible manner. Further, the internal incentives to reduce damage to surface productivity or water quality appear to be modest, given existing surface values and current reclamation costs. Consequently, some reclamation efforts fail or are not even taken making the environmental quality a tradeoff for coal development in some areas. The Surface Mining Control and Reclamation Act of 1977 (P.L. 95-87) established a nationwide program for protection from adverse effects of surface coal mining.

Surface mine reclamation, subsidence prevention, and abatement of acid mine drainage will cost about \$1.2 billion under the BOM scenario and about \$1 billion under the industry scenario by 1985. The Eastern region accounts for 73 percent of these total costs.

Under the BOM scenario, some 99,327 acres of land will be disturbed annually by coal mining in 1985 and 159,143 in the year 2000. Under the industry scenario, some 96,114 will be disturbed by 1985.

In the Western region, a special problem associated with increased coal development is water availability. Surface mining can adversely affect the hydrology of certain areas, causing a lowering of ground-water levels. Coal electricity generation and coal gasification-liquefaction processes require large amounts of water. As western coal deposits are developed, an increasing demand will be placed on water resources for coal conversion and generation of electricity. Potentially, this demand for water may not be met in the West, because of the reluctance to convert water rights from existing uses, and coal may have to be shipped to other geographic areas where water is more plentiful.

Seventeen Federal agencies and departments conduct energy related environmental research and all phases of coal production and consumption are being studied.

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CHAPTER 7

HOW DO WE SOLVE THE SOCIAL PROBLEMS?

Increased coal development will entail costs as well as benefits for the localities in which they occur, and the smaller and more rural the community, the more significant the impact will be. New miners, construction workers, and plant employees will be required in these areas. With the influx of population will come an immediate need for public facilities and services which will require advanced planning and financing if they are to be provided in time to meet the need for them. The newcomers will bring new ideas, values, and behavior patterns; and the old social order will change.

Later, a bust condition may occur. The coal will be depleted or market conditions may change. If sufficient economic diversification is achieved in a region, however, it may reduce the effect of a decline in one industry.

Socioeconomic concerns that will arise with new coal development are:

- Local governments should have advance information on development and the capacity to plan for it.
- Local governments should have the initial financing for the increase in needed facilities and services.
- Social changes must be expected.
- Coal development areas may experience bust conditions arising from a sudden reduction or termination of coal development. Such an eventuality should be planned for and measures taken to avoid adverse impacts.
- Coal development areas will experience socioeconomic changes that should be considered in policy decisions.

ACCURATE AND TIMELY INFORMATION:

A PLANNING NECESSITY

Developers do not always provide accurate and timely data about their plans to local governments, thus preventing the governments from taking action to prevent or mitigate undesirable effects of rapid growth. This was demonstrated in the case of Rock Springs, Wyoming. In January 1970, before any announcement of energy development, the city hired a planning firm to give the city a plan for development. Five months later, two industrial firms announced plans for a coal-fired steam electric plant, with 285

additional employees by 1971 and 920 additional employees by 1974. Based on these figures, there appeared to the city government to be no problems with any ordinary five percent growth rate and normal planning procedures. Then, two things happened which ignited the boom. Plant employment soared to 3,000 people in 1973, instead of 920 people in 1974, and four major chemical plants in the immediate vicinity had plans for major expansion but told the city nothing about them. In addition, related service industries were attracted to Rock Springs, which swelled the population even more. 1/

In January 1972, the city received the plan it had contracted for. On the basis of employment projections furnished by mineral, utility, and construction employers, the plan projected a population increase to 15,000 by 1975 and 26,000 by 1990. Rock Springs actually reached the 1990 figure of 26,000 in 1973. 1/

Some companies recognize that it is in their best interest to convey their plans to local governments because community living conditions can affect workers' productivity. Action has been taken by some to provide local governments with timely information. In Gillette, Wyoming (near which eight new coal mines are planned or under construction, a coal-fired electrical generation plant is being constructed, and a 120-mile long railroad line is planned to be constructed) developers have for at least two years furnished forecasts of their activities, including estimates of employment by year, to the local governments. These estimates were used to prepare a profile of future economic activity included in a 1976 study of economic base and growth potentials commissioned by the local governments, with funding assistance from the State and Federal Governments. 2/ With the information in the report, the local governments should be in a position to plan for future expansion.

Industry possesses the most advanced information on development and the time needed for community development. Companies which recognize a relationship between worker productivity and maintaining an acceptable quality of life in a community will more likely volunteer their plans to local governments and work with them to plan for needed facilities and services.

Note: Numbered footnotes to ch. 7 are on pp. 7.42 to 7.50.

Industry probably cannot be expected to take the initiative in all cases, but States can take actions to encourage or require developers to provide advance notice and accurate data to local governments. Such actions include

- creating authority, either legislatively or by Executive order, requiring advance notification of development, and
- setting, by development permit, definite time periods between the announcement and commencement of development to allow local governments to plan for and begin providing needed facilities. 3/

The Federal Government could, in some cases, become involved in assuring that information needed for planning for coal development at the local level is provided. In 1976, the administration proposed bills to the Congress which would directly or indirectly involve the Federal Government in the subsidizing of energy projects, including development of synthetic fuel production from coal. Such legislation may in the future again be considered by the Congress and could include a provision to require the industry receiving the funds to work with local governments to keep them abreast of development plans.

It should also be noted that much of the coal in the West is on Federal lands. Federal coal lessees could be required to make their plans for development known early enough to enable local governments to act. In addition, in connection with requirements that industry file detailed development plans with the appropriate Federal land management agency, these Federal agencies could also be given a responsibility for keeping the local communities informed at each stage of development.

Currently, the Office of Management and Budget (OMB) Circular A-95 suggests that Federal agencies engaged in direct development of Federal projects should consult with local governments that might be affected by those projects. OMB informed us that they may change A-95 to require that Federal agencies notify local governments of proposed actions and that this requirement would include Federal coal leases. This action might improve the flow of information to local governments and better enable them to plan for meeting the needs of rapid population growth resulting from Federal coal leases.

INITIAL FINANCING WILL BE REQUIRED BY LOCAL GOVERNMENTS

The ability of local governments to provide new and expanded public services is one of the most critical socioeconomic problems associated with coal development. Capital outlays of significant magnitude will be required to provide public facilities and services, such as schools, health care, municipal water services, sewers, parks, playgrounds, roads, and jails. During a period of rapid population growth, services will be needed immediately, whereas revenues will not come until the plants go on the tax rolls and residents become taxpaying citizens. The time disparity between the need for public services and the revenue to pay for them can cause considerable social disruption as well as dissatisfaction with local governments.

An example: Sweetwater County, Wyoming

Rock Springs and Green River in Sweetwater County, Wyoming, illustrate what happens to communities that are unprepared and underfinanced to face rapid population increases. Concurrent rapid development of oil and gas resources, construction of a coal-fired electric generating plant, and development of other mineral resources caused the county's population to rise from about 18,000 in 1970 to about 37,000 in 1974. In the process, the local government's ability to provide necessary services was impaired, industrial productivity dropped, and the quality of life declined. Sweetwater County's population had grown at a compound annual rate of about 19 percent. A five percent compound annual growth rate from 18,000 to 22,000 is about all that could have been easily absorbed without some adverse socioeconomic effects. 4/

The population grew beyond the capability of existing institutions to cope with their needs. With few vacant houses, the permanent housing market was insufficient to accommodate the construction workers brought from the outside, and prices of recently built homes rose too high for the average worker. Little sewage treatment capacity was available, so developers of large housing projects had to build treatment facilities. About half of the land around the communities was federally owned, and the remainder was closely held by a few private owners. The scarcity of available land resulted in high land costs. High interest rates drove home mortgage costs to record highs. Permanent housing units could

not be built fast enough to keep pace with demand. As a result, 4,500 to 5,000 mobile homes were used to accommodate the growth in Sweetwater County. 5/

Other problems also degraded the quality of life. In 1970, Sweetwater County had a ratio of 1 doctor for every 1,800 people. In mid-1974, the ratio had fallen to 1 doctor for every 3,700. The statewide average was 1 to 1,100 6/ and the nationwide average was about 1 to 612. 7/ Health care became a major problem for the county and about 40 percent of its residents had to seek care elsewhere. 8/

The mental health clinic caseload grew ninefold, while the population was doubling. Long-time residents accounted for much of the increase. The rates of alcoholism, broken homes, suicide attempts, and suicide all increased. 9/

Much of the population increase after 1970 was housed outside incorporated communities in scattered fringe developments. Such settlements offered little opportunity or encouragement for newcomers to participate in the community. Social cohesion suffered as alienation and emotional distress fed on each other. 9/

Recreational, cultural, and adult education facilities did not keep pace with growth. Organized year-round recreation for youths was particularly lacking, and extensive expansion of indoor facilities was needed. 10/

Many schools were strained beyond capacity. Both the Green River and Rock Springs school districts were bonded to the State constitutional limit of 10 percent of assessed valuation. They were not able to finance the needed counseling, school social workers, or other personnel to meet the needs of the students. 10/

Retailing and service facilities also failed to expand as rapidly as total employment. Crime rates went up. Burglary and larceny particularly increased tremendously. Telephone service suffered. The cost of living rose faster than the national rate, and local salaries, particularly in local services employment, did not keep pace. In addition, because of the emphasis on construction and mining, employment for women lagged behind total employment. 11/

The problems affecting the quality of life were more than a matter of inconvenience; they disrupted industrial activity in Sweetwater County. Employee turnover rose sharply

in 1973, ranging from 35 to 100 percent among the different mining employers. Both employee turnover and reduced productivity were attributed to difficulties in recruiting and retaining satisfactory employees willing to live under boom town conditions. 12/

The demands on Green River and Rock Springs for additional municipal services, such as police and fire protection and the capital construction costs for water, sewer, and sanitation, surpassed the communities' abilities to pay for them. They supported themselves through revenue sharing funds and a variety of taxes and fees, but these revenue sources offered no increased borrowing capacity. As a result, the local government in Sweetwater County was underfinanced and unable to furnish the basic services and facilities required by growth. 13/

Beginning in early 1974, the growth rate leveled off, giving Sweetwater County and its cities some time to catch up with needed expansion of facilities and services. The slowdown in the growth rate since 1974 was accompanied by substantial increases in assessed valuation and bonding limits. 14/

Measures have been taken by local governments to improve the quality of life in the county. The Rock Springs school district has expanded its capacity and added to its special education staff. The broadened tax base will support needed special education programs, additional teaching staff, and facilities with minimum reliance on borrowing. 15/

Health care capacity in Sweetwater County has been improved by bringing in more physicians (mostly through the National Health Service Corps program) and physician assistants. Additionally, a health maintenance organization, subsidized by the Federal Government has been added; construction of a new county funded hospital has begun; and there has been an expansion of professional psychological counseling services. The level of health services is still inadequate and will require continued attention and effort. 16/

Housing demands have been largely met by considerable single and multifamily construction, mobile homes, single worker complexes, and some substandard housing. New mobile home parks are under construction. With a decrease in construction employment levels, mobile home spaces have become increasingly available. There has been an increase

in permanent housing in Rock Springs, and financing is available for single family units from both commercial banks and savings and loan associations. Permanent housing will still not be available to all who desire it--the housing is too expensive for a large segment of the potential market. Construction workers have difficulty in qualifying for mortgage loans, and a shortage of land and restrictions on sewage treatment facilities have limited development alternatives. 17/

Community programs to provide recreational facilities have been limited; however, an extensive recreational complex is being planned north of Rock Springs by the city and county for completion in 1977. 18/

Traffic problems make travel within Rock Springs time-consuming. The city has set aside money for improving traffic flow and hired professional planners to cope with the problem. The problem of providing adequate police protection has been partially alleviated. 19/

The demand for retail and local services has been partially met by the construction of a shopping center, new motels, and restaurants. However, recreation, daycare, and more shopping facilities are still needed. 19/ And, more growth is on the way for Sweetwater County. Construction of another unit of the electrical power plant is planned. Five new coal mines are expected to be opened. The area's oil and gas production will expand. As a result, the population will probably begin growing again in 1977 and by 1985 is expected to increase by 82 percent from the estimated 1976 population. To keep abreast of these developments, further expansion of local services will be required. 20/

Projections of future income indicate that the county government, Rock Springs and Green River city governments, and the Rock Springs school district will be able to meet the projected operating and capital costs. But the Green River school district may have trouble fulfilling its needs, and financial aid will be necessary to meet capital requirements. 21/

Sweetwater County and the cities of Rock Springs and Green River appear to have reached a point where the quality of life is improving and fiscal resources are adequate. Even with the fairly high average annual population growth rate which is anticipated, 6.9 percent, it is reasonable to expect

that the problems resulting from boom conditions of 1970 to 1974, when the growth rate was much higher, will not return because they will have the financial capacity to meet the projected operating and capital expenses connected with the new growth.

Infrastructure costs: How much is needed?

Per capita costs--Many factors affect the amount of assistance that will be needed to cope with the effects of rapid growth. The rate of future resource development is perhaps the variable that most determines the amount of assistance that communities will require. Other factors bearing on the amount of assistance needed, such as condition of existing facilities, size of the existing tax base, and legal bonding limitations, will vary from community to community. The amount of assistance required can be computed only after the extent and timing of development are known.

Several studies have estimated per capita costs of facilities based on analysis of individual communities. The costs estimated vary widely. Discussed below are costs developed by two studies which represent low and high per capita estimates.

Study A addressed the effects of locating a coal mine near Gillette, Wyoming. The study estimated that the mine would eventually produce 10 million tons annually, resulting in a population increase of 2,090 people to a town of approximately 11,000. The study estimated that the local capital expenditures would amount to \$3,121 per person. 22/

Study B estimated per person growth costs of \$4,892 based on a community of 33,000. 23/ A comparison of estimated costs of facilities and services are shown in the following table.

Table 1

Estimated Per Capita Costs
of Community Facilities and Services (note a)

<u>Type of facility or service</u>	<u>Study A</u>	<u>Study B</u>
Streets and roads	\$ 730	\$1,144
Water	625	583
Sewage and solid waste	500	613
Education	888	1,678
Recreation	130	118
Fire and police protection	148	71
Libraries	46	45
Health care	54	241
Other	-	399
Total	<u>\$3,121</u>	<u>\$4,892</u>

a/1975 dollars

Cumulative costs under different growth rates--Local
governments will collectively incur large costs--perhaps several billion dollars--over the next 20 to 30 years to meet the needs of new population attracted by coal mining, construction of electrical generation plants, and construction of synthetic fuel plants. Although the collective costs are high, it should be remembered that they will be spread over time and over a large number of communities and that some of the areas have relatively large populations and will be capable of absorbing additional population with little problem. Nevertheless, the possibly great magnitude of needed investment and the fact that at least some portion of the needs may occur in communities which are unable to meet them without outside help make it useful to look at what the total required investment could be.

Costs will vary according to the regions affected. They will be lower if most development takes place in the East, rather than in the West, because fewer people will have to move to eastern development areas.

Using the Bureau of Mines and Edison Electric Institute scenarios of future coal production and the BOM scenario for future electrical generation and synthetic fuel plants, we computed local government infrastructure costs that might be required by 1985 and 2000. In total, these costs, which are shown in tables 2 through 7, might run as high as \$4.4 billion between 1974 and 1985 and \$14.9 billion between 1974 and 2000. However, because this figure is based on a high scenario and does not consider the availability of any local labor, a more realistic figure might be half or less. A significant number of the miners and construction workers required for new development will come from the area of the development, but the percentage will vary with the location because of such factors as the size of the existing population and unemployment rates.

Tables 2 and 3 show costs associated with coal mining. Costs associated with mine operations are shown rather than costs associated with opening coal mines because studies indicate that although approximately the same number of workers are needed to open a coal mine as to operate it, the population that comes with operating personnel is greater than that which comes with the temporary personnel involved in opening the mines. These tables are based on the assumption that all workers will come from outside the region and, therefore, do not consider regional differences in expected immigration.

Table 2

Local Government Infrastructure Requirements
Due to Increased Coal Production
1974 to 1985

Coal production region	Population increase		Infrastructure costs			
	<u>BOM</u>	<u>EEI</u>	<u>BOM high</u>	<u>EEI high</u>	<u>BOM low</u>	<u>EEI low</u>
----- (thousands) -----						
East	215,509	39,650	\$1,054,270	\$193,968	\$ 672,604	\$123,748
Central	51,716	27,166	252,995	132,896	161,406	84,785
West	<u>173,370</u>	<u>110,090</u>	<u>848,126</u>	<u>538,560</u>	<u>541,088</u>	<u>343,591</u>
Total	<u>440,595</u>	<u>176,906</u>	<u>\$2,155,391</u>	<u>\$865,424</u>	<u>\$1,375,098</u>	<u>\$552,124</u>

Table 3

Local Government Infrastructure Requirements
Due to Increased Coal Production
1974 to 2000

Coal production region	Population increase		Infrastructure costs			
	<u>BOM</u>	<u>EEI</u>	<u>BOM high</u>	<u>EEI high</u>	<u>BOM low</u>	<u>EEI low</u>
----- (thousands) -----						
East	1,063,388	166,509	\$5,202,094	\$ 814,562	\$3,318,834	\$ 519,675
Central	230,048	40,836	1,125,395	199,770	717,980	127,449
West	<u>321,601</u>	<u>161,981</u>	<u>1,573,272</u>	<u>792,411</u>	<u>1,003,717</u>	<u>505,543</u>
Total	<u>1,615,037</u>	<u>369,326</u>	<u>\$7,900,761</u>	<u>\$1,806,743</u>	<u>\$5,040,531</u>	<u>\$1,152,667</u>

These tables assume:

1. High and low infrastructure costs of \$4,892 and \$3,121 in 1975 dollars.
2. That for each new miner there will be a population increase of 6.5 persons, including the miner, his family, persons engaged in service and related industries and their families.
3. That all workers will come from outside the region.
4. That mine productivity will remain constant at 1974 levels.

Tables 4 through 7 show local government infrastructure costs resulting from construction of electrical generating plants and synthetic fuels plants. Costs were computed on the basis of the estimated number of construction workers needed to build these facilities. Costs associated with operating personnel were not used because unlike the situation with opening and operating new mines, the construction phase work force and accompanying population in these cases will be much greater than the operating phase work force and accompanying population. 24/

Table 4

Local Government Infrastructure
Requirements for Construction of
Coal-Fired Electrical Generation Plants
1974 to 1985

<u>Region</u>	<u>BOM</u> <u>population</u> <u>increase</u>	<u>BOM</u> <u>Infrastructure costs</u>	
		<u>high</u>	<u>low</u>
		(thousands)	
New England	-	\$ -	\$ -
Middle Atlantic	11,172	54,653	34,868
South Atlantic	54,016	264,246	168,584
East North Central	66,643	326,018	207,993
East South Central	23,959	117,207	74,776
West North Central	55,112	269,608	172,005
West South Central	102,950	503,631	321,307
Mountain	72,071	352,571	224,934
Pacific	<u>17</u>	<u>83</u>	<u>53</u>
Total United States	<u>385,940</u>	<u>\$1,888,017</u>	<u>\$1,204,520</u>

Table 5

Local Government Infrastructure
Requirements for Construction of
Coal-Fired Electrical Generation Plants
1974 to 2000

<u>Region</u>	<u>BOM</u> <u>population</u> <u>increase</u>	<u>BOM</u> <u>infrastructure costs</u>	
		<u>high</u>	<u>low</u>
(thousands)			
New England	-	\$ -	\$ -
Middle Atlantic	11,172	54,653	34,868
South Atlantic	54,016	264,246	168,584
East North Central	66,643	326,018	207,993
East South Central	23,959	117,207	74,776
West North Central	55,112	269,608	172,005
West South Central	116,723	571,009	364,292
Mountain	72,071	352,571	224,934
Pacific	17	83	53
Total United States	399,713	\$1,955,395	\$1,247,505

These tables assume:

1. High and low infrastructure costs of \$4,892 and \$3,121 in 1975 dollars.
2. That all construction workers come from outside the local community. About 60 percent may bring their families, with an average family size of 3.7 persons.
3. For each construction worker, 0.6 secondary workers will be required. Forty percent of these secondary workers will have families, 40 percent will not, and 20 percent will be local residents (not adding to the population). 24/
4. That all plants are operating at 46 percent of capacity in 1985 and 60 percent in 2000 in accordance with the BOM scenario, and that all plants require the same number of workers at both capacity percentages.

Table 6

Infrastructure Cost for the Construction
of Synthetic Fuel Plants in the United States

<u>Year</u>	BOM <u>population</u> <u>increase</u>	BOM <u>infrastructure cost</u>	
		<u>high</u>	<u>low</u>
		(thousands)	
1985	63,750	\$ 311,865	\$ 198,964
2000	1,032,750	5,052,213	3,223,213

This table assumes that all construction workers will come from outside the local community.

Table 7

Comparison of Infrastructure Costs Assuming
Total Immigration and Partial Immigration for
the Construction of Synthetic Fuel Plants in the United States

<u>Year</u>	Total immigration (<u>note a</u>)	Partial immigration: 50-50 allocation <u>of plants (note b)</u>	<u>Difference</u>
----- (thousands) -----			
1985	\$ 311,865	\$ 146,577	\$ 165,288
	198,964	93,513	105,451
2000	5,052,213	2,374,540	2,677,673
	3,223,213	1,514,910	1,708,303

a/This column assumes that all construction workers will come from outside the local community.

b/This column assumes that some construction workers will come from the local community. Immigration rates of 34 percent were used for the East and 60 percent for the West. It was assumed that the allocation of synthetic fuel plants between East and West would be equal.

Both tables above assume high and low infrastructure costs of \$4,892 and \$3,121 in 1975 dollars.

Infrastructure requirements will be considerably lower if development takes place primarily in the East rather than in the West because fewer people will have to move to eastern development areas. Tables 8 and 9 are an attempt to show the effect of lower immigration rates expected in the East.

As shown in table 9, estimated costs associated with constructing synthetic fuel plants under the BOM scenario for 2000, if 75 percent of the plants are built in the West, might be \$2.7 billion; however, if 75 percent of the plants are built in the East, the total cost might be reduced by \$656 million to \$2.05 billion. Synthetic fuels plants were used to illustrate the magnitude of differences that might occur as a result of different geographic distributions of development. The geographic mixes used in the table are for illustrative purposes only and not based on any known proposals.

Table 8

Local Population Increases Due to
Constructing Synthetic Fuel Plants
in Different Parts of the United States

<u>Year</u>	<u>Allocation of plants</u>			
	<u>75 percent West</u> <u>25 percent East</u>	<u>50 percent West</u> <u>50 percent East</u>	<u>25 percent West</u> <u>75 percent East</u>	
1985	34,106	29,963	25,819	
2000	552,521	485,393	418,264	

Table 9

Local Infrastructure Cost Due to
Constructing Synthetic Fuel Plants
in Different Parts of the United States

<u>Year</u>	<u>Allocation of plants</u>		
	<u>75 percent West 25 percent East</u>	<u>50 percent West 50 percent East</u>	<u>25 percent West 75 percent East</u>
	----- (thousands) -----		
High-1985	\$ 166,847	\$ 146,579	\$ 126,307
Low-1985	106,445	93,515	80,581
High-2000	2,702,933	2,374,543	2,046,147
Low-2000	1,724,418	1,514,912	1,305,402

These tables assume:

1. High and low infrastructure costs of \$4,892 and \$3,121 in 1975 dollars.
2. That for each new construction worker there will be a population increase of 4.25 persons including the worker, his family, persons engaged in service and related industries and their families.
3. Some construction workers will come from the local community and are based on a 34 percent construction worker immigration rate for the East and 60 percent for the West.

What is being done?

Because the socioeconomic costs of rapid coal development are beyond the immediate means of many communities, they look to their State government, the Federal Government, and industry for assistance. Some States have enacted legislation intended to mitigate the effects; the Federal Government has provided limited assistance; and industry has provided assistance in a few cases. Collectively, these action provide limited solutions.

What is being done by the States?

Western States--The legislatures of some coal producing Western States have considered bills that could provide the mechanisms and funds for planning, designing, and building to at least partially offset the effects of energy resource development. In 1975, Wyoming enacted a package of laws to help its communities finance solutions to the problems of rapid growth. Montana, North Dakota, and Utah passed laws which will provide significant assistance, and Colorado and New Mexico enacted laws to provide limited assistance.

Wyoming created a community development authority, which is authorized to issue up to \$100 million in revenue bonds, the proceeds of which are to be used to make loans to local jurisdictions for a wide range of civic facilities. The proceeds can also provide home loan capital funds to communities through savings and loan institutions. 25/ In addition to a four percent severance tax, Wyoming levied a 0.4 percent tax on the value of coal mined in 1974 which will increase to two percent of the value of coal mined in 1978 and later. Collections from the latter tax can be granted or loaned to areas affected by coal production and can be used in financing public water, sewer, highway, road, and street projects. 26/

Wyoming also enacted several other laws in 1975 to aid affected communities. One law increased the maximum rates for school district taxes. 27/ An existing law was amended to allow cities and counties to combine for public projects voluntarily, enabling localities to solve tax imbalances (for instance, when resources are developed in a county, but greatest effects are on a city). 28/

Montana passed the highest surface-mined coal severance tax in the Nation. The tax rate is 20 percent of the selling price of low-grade lignite coal and 30 percent on other coal. 29/ Large amounts of revenue are expected from the tax. One study estimated that by 1985 between \$266 million and \$1.1 billion in severance taxes will be collected on the coal from the two largest Montana coal producing counties. 30/ Statewide, Montana expects proceeds through 1977 to total \$66.6 million. The proceeds are to be distributed as shown in table 10.

Funds will not be used primarily for affected areas, however. About \$11.7 million (17.5 percent) will be put in a local impact fund, which will be used to pay the expenses of a coal board and to make grants to affected communities; \$6.7 million (10 percent) will go for coal area highway

improvement; and \$2.7 million (four percent) will be returned to the coal producing county. After June 1977, the percentage of the severance taxes allocated to the local impact fund will be reduced to about 11 percent, which in turn will reduce the total designated specifically for the coal producing areas to 25.7 percent of the total severance tax collected.

Table 10

Allocation of Montana Severance Tax Funds

<u>Allocation to</u>	<u>Percentage 31/</u>	<u>Amount</u> (millions)
General fund	40.0	\$26.6
Local impact fund	17.5	11.7
Educational trust fund	10.0	6.7
Coal area highway improvement	10.0	6.7
State equalization aid to public schools	10.0	6.7
Return to the coal generating county	4.0	2.7
Alternative energy research	2.5	1.6
Park funds	2.5	1.6
Renewable resources development	2.5	1.6
County land planning	<u>1.0</u>	<u>.7</u>
Total	<u>100.0</u>	<u>\$66.6</u>

The actions that Wyoming and Montana have taken to provide local impact funds from severance taxes will help to provide needed initial financing assistance. Table 11 shows a comparison of severance tax funds earmarked by States for local impacts with estimated infrastructure funding requirements using the BOM and EEI scenario projections of expected coal production by 1985 and 2000.

The table shows that in Montana there will be far more available impact funds than will be needed. This finding corresponds to that of a December 1976 Resources for the Future, Inc., study. This study focused on two Montana counties--Rosebud and Big Horn--where future coal development is expected to occur on a large scale. 32/

Table 11

Comparison of Cumulative and Net Local Infrastructure Costs and
Impact Funds for Montana and Wyoming (note a)

	<u>1975 to 1985</u>		<u>1975 to 2000</u>	
	<u>BOM</u>	<u>EEI</u>	<u>BOM</u>	<u>EEI</u>
<u>Montana</u>				
1. Local impact funds available	\$189.8 million	\$156.9 million	\$744.5 million	\$515.0 million
2. Local infrastructure costs	\$ 54.6 million	\$ 36.0 million	\$ 98.2 million	\$ 51.4 million
3. Per capita local impact funds	\$17,010	\$21,347	\$37,074	\$49,005
4. Local infrastructure cost per capita	\$ 4,892	\$ 4,892	\$ 4,892	\$ 4,892
5. Excess impact funds per capita (note b)	\$12,118	\$16,455	\$32,182	\$44,113
<u>Wyoming</u>				
1. Local impact funds available	\$110.7 million	\$87.3 million	\$565.4 million	\$378.7 million
2. Local infrastructure costs	\$370.9 million	\$290.8 million	\$632.9 million	\$351.5 million
3. Per capita local funds	\$1,460	\$1,473	\$4,370	\$ 5,270
4. Local infrastructure cost per capita	\$4,892	\$4,892	\$4,892	\$ 4,892
5. Excess impact funds per capital (deficit) (note b)	(\$3,432)	(\$3,419)	(\$522)	\$ 378

a/ All values in 1975 dollars.

b/ Monetary position shown in line 5. is the difference between lines 3. and 4.

North Dakota enacted legislation that created a coal development office which is responsible for disbursing funds collected from two taxes. One is a tax on electricity and gas produced by coal-fired electrical generating plants and coal gasification plants. The first \$100,000 collected from each plant annually is returned to the county. Revenues above \$100,000 are divided between the county and the State. The other tax, levied at a rate of 50 cents per ton of coal, increases with rises in the wholesale price index. Thirty-five percent of the coal tax will be put in a coal development impact fund, which is expected to total about \$4 million by mid-1977. This fund can be used for grants to impacted political subdivisions. 33/

Utah enacted a package of laws aimed at mitigating socioeconomic effects of projects. The key bill of the package allows developers to voluntarily prepay sales or use taxes. Under the Utah law, the developer can pay the taxes before installing the equipment on which the tax applies. Taxes will be deposited in a fund which can pay for public projects related to the development. 34/

The bill allowing prepayment of taxes was aimed primarily at development in southern Utah, where a major power plant complex and mine were to be built and where no town existed. It was intended to facilitate the financing of facilities needed for a new town. The Governor of Utah stated that companies would have an incentive to prepay taxes for developing new towns because the companies will not be able to get employees without helping fund community development. Although the companies later withdrew from the project, some taxes were prepaid prior to withdrawal.

New Mexico levies a severance tax of 0.5 percent of the gross value of the coal and a resources excise tax of 0.75 percent of the value of the coal less royalties. Colorado levies the lowest of all State-level coal severance taxes at 0.7 cents per ton. 35/

Legislatures of other States in the area wrestled with numerous land use, mineral tax, and impact aid bills during their 1975 legislative sessions. Many laws were enacted, but none are sufficient in scope to provide aid needed by affected communities.

Eastern States--Five Eastern coal producing States--Kentucky, West Virginia, Alabama, Virginia, and Tennessee--have coal production based taxes. Pennsylvania and Maryland

have none. Of the five having coal taxes, three--Kentucky, West Virginia, and Tennessee--collect them statewide and return a portion of the tax to the counties where the coal is extracted. Tennessee returns 99 percent of a 20-cent per-ton tax; West Virginia returns 0.2625 percent of the gross proceeds from the sale of coal by the producer; and Kentucky returns a dollar amount set by the State legislature. 36/

Counties use their share of the tax for a wide variety of purposes. In Kentucky, \$5 million each year from the Coal Severance Economic Aid Fund is distributed to the counties to be used for capital projects, excluding road or school projects. In addition, \$12 million in fiscal year 1976 was allocated to coal producing counties for road improvements from the Energy Road Fund. Additional coal severance tax revenues are earmarked for highway construction, worker's compensation, and area development programs. The remainder of the revenues are kept in the State General Fund. In Tennessee, the counties must expend 50 percent of the funds for highway maintenance and water pollution control and 50 percent for education. West Virginia permits the county commissions to decide how they will spend their share of the State Business and Occupation Tax. 36/

Some States have enacted laws permitting counties to levy coal production based taxes. Alabama has authorized two counties to levy a severance tax on coal mined in those counties. Indications are that other coal producing counties will be authorized by the legislature to levy similar severance taxes on coal production. 37/ Virginia has permitted counties to levy a local gross receipts tax on coal production up to a maximum rate. 38/

In Pennsylvania, an attempt to institute a severance tax for mining conservation and reclamation was defeated because counties already have the authority to require coal companies to post performance bonds against damage to any transportation facility and to require land reclamation. 39/

Central States--Of the three Central States, only Illinois has taken measures intended to aid communities affected by coal development. In Illinois, local sales taxes on coal sold for use in Illinois are returned to the county where mining occurred. Ohio has a coal production based tax, the proceeds of which are used for environmental protection activities and strip mine reclamation. None of the proceeds are used to mitigate socioeconomic impacts of coal development.

Indiana has no coal severance tax and does not provide financial assistance to communities affected by coal development. 40/

What is being done by the Federal Government?

Funds that can be used to plan for or mitigate energy-related effects are provided to communities under numerous Federal programs and are allocated in competition with non-energy-related needs. Communities compete for funds; and the small communities which are affected by coal development sometimes have trouble qualifying or competing with larger communities and communities having needs related to highly visible programs, such as programs for high poverty areas and Indian reservations. Nevertheless, under existing agency policy and regulations, some programs and projects can and have been used to deal with coal development effects.

In the Western States--Sixty-two percent of the 1974 coal production in the West came from 10 counties in 7 States. 41/ As shown in the table 12, Federal grants and loans for community and economic development, loans and loan guarantees for housing, and grants for revenue sharing made to these counties in Arizona, Colorado, New Mexico, North Dakota, Montana, Texas, and Wyoming in fiscal year 1975 amounted to \$75.1 million. 42/

Table 12

Federal Dollars to the Ten Top Coal
Producing Counties in the West
Fiscal Year 1975

<u>Purpose</u>	<u>Grants</u>	<u>Loans</u>	<u>Total</u>
	----- (thousands) -----		
Community and economic development	\$44,408	\$11,363	\$55,771
Housing loans and loan guarantees	-	15,693	15,693
Revenue sharing grants	<u>3,625</u>	<u>-</u>	<u>3,625</u>
Totals	<u>\$48,033</u>	<u>\$27,056</u>	<u>\$75,089</u>

In the West, Federal agencies attempted, through the Mountain Plains Federal Regional Council, to coordinate Federal efforts to aid affected communities. The Council is 1 of 10 Federal Regional Councils (FRCs) established by Executive order to assist State and local governments by coordinating Federal program grants and operations. The Council is composed of the principal regional officials of the Departments of Commerce; Labor; Health, Education, and Welfare; Housing and Urban Development; Agriculture; the Interior; and Transportation as well as the Federal Energy Administration, the Community Services Administration, the Environmental Protection Agency and the Law Enforcement Assistance Administration. The Mountain Plains Council is responsible for Federal Region VIII--the States of Colorado, Montana, North and South Dakota, Utah and Wyoming. It is responsible to the Under Secretaries Group (USG) for Regional Operations chaired by OMB's Deputy Director.

USG has given the FRCs permission to provide on request technical assistance to State and local governments on approaches for mitigating the effects of socioeconomic impacts and to respond to the requests from State and local governments for integrated or coordinated funding of categorical programs normally administered by regional offices. In late 1975, the Mountain Plains Council began a small project to help communities assess their needs and to advise them of possible sources of financial and technical assistance.

In March 1976, the USG assigned FEA lead-agency responsibility for all FRC energy-related activities. FEA established a small office in Denver with fiscal year 1976 goals of insuring coordinated action in programs and projects focused on the mitigation of negative energy impacts and monitoring and streamlining national and regional data efforts. The office, which was not fully staffed until early 1976, had

- participated with FRC in planning and implementing projects associated with the socioeconomic impact committee,
- taken over and expanded on the FRCs' socioeconomic data gathering efforts,
- participated with Wyoming in a project to demonstrate and evaluate the effectiveness of statewide systems and strategies in dealing with impacts of energy development,

--assisted in a joint project with Colorado and the local Council of Governments in helping one Colorado community analyze its needs and formulate plans to finance projects, and

--entered into a contract for a Colorado special census study.

In addition to the funds provided in the past, the Federal Government recently increased funds to the States which can be used to aid energy-affected communities. These funds are derived from Federal minerals and lands and will, therefore, be primarily available to Western States.

In August 1976, the Mineral Leasing Act of 1920 was amended to greatly increase the royalties collected on coal and to increase the royalties returned to States from mineral leases on Federal lands from 37.5 percent to 50 percent. 43/ Royalties to the States from coal resulting from these changes have been estimated by the Department of the Interior to rise from \$3.4 million in 1976 to \$126 million in 1985. 44/

In October 1976, the Congress enacted the Federal Land Policy and Management Act of 1976, enabling the royalties returned to States to be used as the legislatures of the States direct. It gave priority to subdivisions of the States socially or economically impacted by development of Federal minerals leased under the act for planning, constructing, and maintaining public facilities and providing public services. The act also provided for loans to States and political subdivisions in order to relieve social or economic impacts occasioned by the development of Federal mineral leasing. Loans can be made up to the anticipated mineral royalties to be received by the recipients for any prospective 10-year period. 45/

In the Eastern States--Sixty-one percent of the 1974 coal production in the East came from 24 counties. 46/ As shown in the table below, Federal grants and loans made to these counties in Appalachia and western Kentucky in fiscal year 1975 totaled \$461.8 million. 47/

Table 13

Federal Dollars to the Top Coal
Producing Counties in the East (note a)
Fiscal Year 1975

<u>Purpose</u>	<u>Grants</u>	<u>Loans</u>	<u>Total</u>
	----- (thousands) -----		
Community and economic development	\$299,759	\$ 31,406	\$331,165
Housing loans and loan guarantees	-	72,928	72,928
Revenue sharing grants	<u>57,665</u>	<u>-</u>	<u>57,665</u>
Totals	<u>\$357,424</u>	<u>\$104,334</u>	<u>\$461,758</u>

a/Aid to cities with over a 25,000 population is excluded.

The Appalachian Regional Commission has allocated money specifically to help coal-affected communities. A program was approved in December 1975 to meet increased housing and related public facility needs in areas of the region impacted by energy production. In many instances, the Commission's proposals represent commitments by industry, labor, and government jointly to address housing needs in areas impacted by energy production. 48/ As of July 30, 1976, eight projects in coal areas had been approved for funding with a total Appalachian Regional Commission contribution of \$2,435,070. 49/

In recent years, the Tennessee Valley Authority, acting in its role as energy developer, has assessed the socio-economic impact of its major projects and has attempted to offset adverse temporary conditions caused by the project. When needed, mitigation programs have been developed specifically for each project based on the size of the project and the particular local area. Thus, the mitigation programs have varied from project to project. 50/

An example of the TVA program is the Hartsville nuclear project, located near Hartsville and Carthage, Tennessee,

where a substantial effort is planned to mitigate socioeconomic impacts of an electric utility plant. 51/ The socioeconomic impacts related to the influx of population to the community are similar for both construction of coal burning or synthetic fuel plants and for nuclear utility plants. 52/ TVA has agreed to provide necessary financial, technical, or equipment assistance in a timely manner so that small community budgets are not significantly overburdened by long- or short-term indebtedness associated with immigrating construction workers. Assistance will be provided in the areas of housing, job training and recruitment, and education as well as for water and sewer facilities, local government budgets, health and medical services, employee transportation, planning, and monitoring. Total program cost is expected to be \$10.8 million over an 11-year period. 53/

The rationale for the Hartsville impact mitigation program is to finance corrective action from project funds. Adverse socioeconomic impacts are considered a direct consequence of carrying out the project and, therefore, a responsibility of TVA, the major area employer and resource development agency. 54/ The amount of money spent on mitigating socioeconomic problems is negligible, considering the total project construction cost of \$2.5 billion. 55/

In the Central States--Sixty percent of the 1974 coal production in the Central region came from 10 counties. 56/ As shown in the table below, Federal grants and loans made to these counties in Illinois, Indiana, and Ohio in fiscal year 1975 amounted to \$98.7 million. 57/

Table 14

Federal Dollars to the Ten Top Coal
Producing Counties in the Central States (note a)
Fiscal Year 1975

<u>Purpose</u>	<u>Grants</u>	<u>Loans</u>	<u>Total</u>
	----- (thousands) -----		
Community and economic development	\$59,316	\$18,333	\$77,649
Housing loans and loan guarantees	-	15,580	15,580
Revenue Sharing grants	<u>5,489</u>	<u>-</u>	<u>5,489</u>
Total	<u>\$64,805</u>	<u>\$33,913</u>	<u>\$98,718</u>

a/Aid to cities with over a 25,000 population is excluded.

What is being done by industry?

In the Western States--Industry has provided assistance to affected communities in a few cases. Industry provided funds to communities in Sweetwater County for public projects because the degraded quality of life had caused high employee turnover and productivity decreases. New town feasibility studies were prepared by industry for several areas.

Industry has also provided housing. In Colstrip, Montana, a virtual ghost town a few years ago, the energy developer who owns the town planned community expansion and constructed parks, a shopping area, recreation facilities, and housing, which it rents or sells to its employees. Several energy developers in the Gillette, Wyoming, area are constructing homes, but only because high interest rates and labor unavailability have driven away home construction companies.

Although industry has provided some assistance, it is generally reluctant to do so. According to an Exxon official

"* * * industry should not be cast in the role of government by being responsible for planning and constructing public facilities due to its impact. Government should not expect business to be any better in this role than business expects government to be in the business role. On the other hand, business should--and could--pay its fair share for its impact.

"* * * industry must be willing to freely communicate its plans to government and to pay its fair share of taxes so government can handle the impact problems." 58/

Another corporate official outlined several industry policy changes that he believes are needed if the Rocky Mountain area is to produce the minerals required to meet the Nation's energy needs. He believes that industry should:

- Reinvest a larger share of its profits in the area, especially if the increased production of minerals results in increased costs to the local society or local government.
- Make its development plans available to local governmental units so that local and State agencies can plan for the population influx.

- Help plan and fund technical education and the re-training and relocation of skilled workers.
- Spend more money for research on the issue of local impact, aimed at specific regional problem solving.
- Help provide solutions to social problems. 59/

According to the same official, there is too often a lack of coordination and communication between industry and government, and long-range planning between them is either virtually non-existent or proceeds in different directions. 60/

In the Eastern States--The coal industry in the East has taken measures in some scattered instances to help mitigate socioeconomic impacts of coal development. For example, coal companies have

- donated land with a value of \$153,000 for a housing development,
- provided a \$100,000 interest free loan for a housing project, and
- donated \$350,000 to \$400,000 to build a new high school gymnasium. 61/

Coal industry efforts to mitigate socioeconomic impacts of their developments vary widely in Appalachia. The willingness of industry to help impacted communities varies from active participation to an attitude that the impacts are purely public sector problems. A spokesman of one coal company said that they have recently taken a more active interest in helping communities plan for socioeconomic impacts and assisting them in providing mitigation measures. This company believes it receives benefits from improving the quality of community life because workers are more productive and efficient and there is less turnover. 62/

In the Central States--The coal industry in the Midwest has participated to some extent in social and civic activities of coal communities by such things as donations to the Boy Scouts, Girl Scouts, local baseball team, etc. One coal industry official explained that coal mining is a tradition and way of life in the Midwest. Generally speaking, the impacts of increased development are reduced because needed towns and the labor force are already in existence near new mine openings or expansions. 63/

Additional assistance

Early financing assistance must be provided in some areas, especially in the West. The States, the Federal Government, and industry could all contribute.

By taking appropriate steps, the States can provide much of the aid needed by affected communities. The States have various mechanisms available for raising money and distributing it to needy communities without directly taxing the States' populations. These mechanisms include levying severance taxes on extracted resources; creating a bonding authority to issue special revenue bonds, the proceeds of which can be used to make loans repayable by local governments; and using discretionary Federal funds under existing programs.

Severance taxes on energy resources result in the ultimate energy consumer paying for the aid provided to communities.

States could provide incentives for industry participation similar to those provided by Utah in allowing industry to voluntarily prepay sales or use taxes. If necessary, States could also require industry to post performance bonds to cover the cost of local planning and designing of infrastructure, which would be forfeited if, as a result of an industry decision, development does not occur. Thus, the prepayment of taxes could provide the community with additional front-end funds, and the requirement of a performance bond would provide the State and local governments with insurance against the risk inherent in providing facilities and services before growth occurs.

Federal programs that have provided aid to communities generally (1) are not specifically designed to help small communities cope with rapid population growth and (2) are administered by a number of agencies with little coordination. The efficiency and effectiveness of Federal aid to affected communities probably would be increased if one agency were made responsible to coordinate the Federal role.

Industry could contribute significantly in helping to meet the socioeconomic impacts of energy resource development. Prepayment of corporate, sales, and use taxes would help States to provide facilities and services where few or none existed prior to development. Industry might have an incentive to prepay its taxes in this situation because it will be better able to attract employees to live in and work in an area or to commute to an area (and reduce construction and operating costs) if basic public facilities and services are available.

Industry does not generally favor prepayment of taxes because it would increase a company's capital needs and total costs prior to receipt of income on a project.

SOCIAL CHANGES CAUSED BY COAL DEVELOPMENT

The new growth accompanying the construction of new facilities, such as mining operations, can cause effects beyond the problems of land use, housing, and financing. 64/ There are certain social changes accompanying rapid population growth which a community will undergo regardless of how carefully it has planned influx or how adequately it has been financed. 65/ The newcomers bring new ideas, values, and behavior patterns which affect the socio-cultural structure to the community. 66/ As a result, the old social order may disappear. 67/

How and where the population growth occurs will substantially affect the urban-rural mix within the regions. The largely rural character of the regions will undergo change towards a more urbanized society. 68/ The lives of both the new and old residents may be affected as the traditional rural heritage gives way to new tastes and cultural backgrounds. In rural communities a relatively small group of people interact in activities, friendships, and formal and informal institutions. As the population increases, these relationships may collapse. 69/ A change in quality of life is often evidenced by

- a quickened pace of life;
- congestion and overcrowding;
- inflation in prices;
- lack of activities and sense of belonging for new families; and
- alcoholism, drug abuse and other mental health problems. 70/

Even though rural political systems are becoming more integrated with the national system, they still differ from urban political systems. Rural governments are distinguished by the personalism with which decisions are made, leaders are chosen, and policies are implemented. As development occurs, the political system will become more complex and more impersonal. 71/ The long-time residents may lose control of the community, as the new population or industry takes over local affairs. 72/

The effect of a new large development on a region is inversely proportional to the size of the existing population. 73/ The changes which accompany increased coal development are more significant in sparsely populated areas than in more heavily populated areas. 74/ New development is more readily and easily absorbed; in the latter due to a larger existing work force and service base, higher levels of existing community services and more diversified populations. 75/

According to a Pennsylvania powerplant siting study, social impacts are dependent on current community attitudes. Areas which have remained residential in character are unlikely to be receptive to development. In a declining industrial region, where the economy and jobs are prime considerations, public reaction might be totally different. 76/

Some of the new jobs created will be taken by the unemployed of the region. 77/ The hiring of unemployed workers is a critical part of satisfying the labor demand for the mining operation. 78/ However, the jobs created by increased coal development probably cannot be filled entirely by local people. As a result, workers must be recruited from elsewhere. 79/ The more jobs that can be filled by local labor or by commuters from surrounding areas, the less severe the social change caused by the development will be.

Commuting is an important aspect in evaluating the effects of increased coal development. Workers who commute to the job do not disrupt the existing socioeconomic stability of a community. The more workers living within commuting distance of the development, the less likely there will be adverse socioeconomic changes. 80/

West

The West will probably experience a more significant population increase and more severe social changes than either the Midwest or Appalachia. Population growth associated with coal development will not be evenly distributed throughout the West. 81/ Rapid population increases will be concentrated in small, isolated towns. Most of these small, homogeneous communities will be in a poor position to deal with the rapid growth. These communities will have to build additional public facilities in order to absorb the new population.

Substantial immigration will be necessary if labor needs are to be met. Since the region does not have high unemployment or underemployment, there is little surplus labor available. 82/ Workers will not be able to commute from their present residence because development sites are far from population centers. 83/

Even though mining is not new to some Western areas, agricultural activities have been the principal economic base. 84/ The sudden, large demand for employees will shift the local economy base from agriculture to energy. 85/

Western history is recent but traditions are deep. Many of the families which created the communities are still living in them. These communities have not been diversified by massive immigration like Denver and Billings. 86/

Residents of small, rural western towns are generally uncertain about growth and development. Their perceptions of life style changes are subjective and range from hostility to enthusiasm. People's attitude toward change appear to be influenced by their personal expectations and past experiences in the community. 87/ When residents perceive the development will end the rural, neighborly way of life they have sought and enjoyed, they may strongly oppose it. 88/ Individuals with higher incomes who have recently moved into the community and who prefer the rural life tend to be hostile to change. Lower income residents generally favor the changes that accompany growth. 89/

A recent study by the Old West Regional Commission surveyed the attitudes of long-time residents and newcomers concerning construction projects in their community. There was a tendency for those who had lived in an area more than 15 years to be more dissatisfied than those who had lived there for less time. When asked why they were glad the project came to the area, long-time residents indicated job opportunities and financial benefits. The reasons most frequently given for being unhappy were community related, such as town problems, increased population, and inadequate community facilities.

The newcomers also cited job-related factors as what they liked most about living in the community. When asked what they disliked about living in the affected communities, the newcomers most frequently gave answers concerning the environment, physical surroundings, and inadequate community facilities. 90/

East

Appalachia, a major resource area for coal, has been characterized by high unemployment rates, low average family incomes and a high rate of migration to other areas. There was a significant decline in job opportunities during the 1950s and 1960s, and much of Appalachia suffered severe population losses. As the Nation's major coal-producing region, Appalachia bore the brunt of the decline in jobs and production. Coal employment in the region fell from 427,600 in 1947 to 144,914 in 1961, a decline of 65 percent. 91/ Between 1950 and 1970, an estimated one million people 92/ migrated out of central Appalachia as young people left the area to find employment. 93/ This trend was reversed between 1970 and 1975, when it was estimated that the population of Appalachia grew by 750,000. 94/ The recent upsurge in coal demand offers an opportunity to accelerate the development of Appalachia. 95/

Rural Appalachia has been characterized by undereducation, simple life styles, and extreme poverty. 96/ Unemployment and underemployment have been and remain Appalachia's most severe economic problems. 97/ During 1976, the eastern coal producing counties had an annual average unemployment rate of 7.5 percent and 250,987 people were unemployed. Increased coal development would be an important socioeconomic stimulus. 98/

The population density of the East is much greater than that of the West. 99/ Even though coal development will occur in predominantly rural areas, some of the areas are within commuting distance of population centers. 100/ As a result, many workers will be able to commute from their present residences to their jobs. Some Appalachian communities which will be affected if increased coal development occurs are located in rugged terrain and are relatively remote from metropolitan areas. 101/ Workers will not be able to easily commute to these areas. Scarcity of housing will be a problem in some mountain communities and there is little land suitable for housing because of the rugged terrain. 102/

Central

Increased development of Central coal will be in areas where people have lived with coal mining for many years. The population has been declining, and the area has been economically depressed, primarily because of the recession in the coal industry. Unemployment has been a problem in the region

and there have been some significant poverty areas. Increased coal development will create new and expanded job opportunities which should lead to higher income levels.

Few studies of the possible effects of increased coal development have been done. Apparently most people believe there will not be significant negative effects. Based on conversations with many State and Federal officials, we concluded that the social impacts of population growth in the Central region may not be as severe as in the West. The population density in the Central region is generally greater and towns are not as far apart. Since several communities may be located within commuting distance, the effects may be more equitably distributed. In many cases, the increase would be added to an existing population and service base, so the effects may not be much of a problem.

Heavily populated areas, such as the Eastern and Central regions, are more able to absorb the effects of coal development than less populated areas. Lifestyle conflicts would not be as severe in populated areas; they would also be easier to resolve. Population concentrations are larger and coal development will probably occur near large towns. Fewer people will have to relocate in the Eastern and Central regions since most of the labor will be available locally or within commuting distance.

Even though some eastern communities may experience substantial population increases, the social conflict should be minimal because:

- Most people have a positive attitude toward the increased coal development and the accompanying population increase.

- Many of the people who left Appalachia during the 1950s and the 1960s are moving back. If this trend continues, cultural and family ties of the people returning to Appalachia should reduce the social conflict.

PLANNING FOR LONG-TERM ECONOMIC GROWTH

Bust conditions are local economic depressions which can occur in communities and local areas whose economies are dependent on one industry when that industry's production declines. They can also follow boom conditions caused by the construction or expansion of powerplants, synthetic fuel

plants, or any other activity that causes a rapid influx of population to an area. Studies indicate that the bust problem is two-fold. First, if new facilities and services are provided for community residents during the boom or expansion period, then there is likely to be an overcapacity after the boom or expansion period is complete. And, as workers begin to leave, the community may no longer be able to support the same level of services. Second, employment opportunities generated in the community due to the boom conditions may no longer be available, and unemployment may become a major problem. 103/

The economic conditions that have occurred in Appalachia serve as an example of the problem. As the Nation's most important coal-producing region, Appalachia bore the brunt of cyclical booms and busts in the coal production industry. 104/ With the decline in coal production during the 1950s, the Appalachian States found themselves locked in a circle of poverty and deprivation. 105/ Low wages were prevalent in the coal industry, and limited income meant limited services. 106/ Furthermore, lessening demand for coal accompanied by improved mining technology left thousands of miners unemployed. No severance taxes were levied on the coal industry, heavy coal trucks damaged already poor roads, and State and local governments benefited little from the depletion of coal resources. 107/

The 1950s were a time of migration from Appalachia. There was a shortage of jobs and lack of retraining programs. The financial burdens of the States were complicated by the loss of their most productive people. Fewer people were paying taxes, and more were demanding services. The States lacked the expertise and resources to acquire their fair share of Federal dollars. Most Federal programs required matching money on the State or local level, and the Appalachian States did not have the money. State and local governments were crippled with the following socioeconomic problems:

- Inadequate and dangerous highways.
- One of the worst housing conditions in the Nation.
- Thousands of rural residents without health care.
- Educational systems unable to afford programs to train people in economically viable skills.

--An inability of local governments to afford modern water and sewer systems.

--A general lack of amenities that improve the quality of life. 107/

What is being done?

Although the impact of a slowdown in coal production would probably cause local economic problems in coal producing areas, economic development and industrial diversification minimize adverse effects of bust conditions on local economies. According to several studies, the long-term economic vitality and stability of communities in coal producing areas is improved when investments are made in industries other than coal. 108/ Therefore, economic diversification as an alternative to bust conditions, should be considered by local governments. There are presently numerous Federal, State, and local programs which encourage community economic development and diversification.

By State and local governments

A wide variety of State and local programs exist to attract industry and promote economic development in the coal producing States. All the coal producing States provide mechanisms or have programs to promote economic development through financial assistance, industrial bonds, tax incentives, pollution control incentives, and special incentives, services, and aids. Furthermore, most coal producing States have promotional advertising programs. Of course, the number and type of mechanisms used to attract industry vary from State to State. 109/

The funding for State industrial development agencies in the coal production States is shown in table 15. 110/ Much more money was spent on State activities to promote industrial development in the Eastern and Central coal regions of the United States than in the West. In fact, on the average, Eastern and Central States spend about four times more per capita on such activities than do Western States. 111/

Table 15
Industrial Development Agency Funding
in the Coal Production States (1975)

<u>State</u>	<u>Department</u> <u>total</u>	<u>Industrial</u> <u>development (note a)</u>	<u>Industrial</u> <u>development</u> <u>advertising</u>
<u>East</u>			
Alabama	\$ 1,655,000	\$ 650,000	\$ 45,000
Arkansas	1,032,000	602,000	160,000
Kentucky	2,836,400	270,300	125,000
Maryland	4,929,000	319,000	141,000
Pennsylvania	16,623,000	5,560,000	600,000
Tennessee	4,407,000	454,000	200,000
Virginia	1,290,000	645,000	315,000
West Virginia	3,291,000	334,000	96,000
Total	<u>\$36,063,400</u>	<u>\$ 8,834,300</u>	<u>\$1,682,000</u>
<u>Central</u>			
Ohio	\$ 80,811,000	\$ 724,000	\$ 30,000
Illinois	5,222,600	1,527,800	-
Indiana	1,304,922	83,000	139,000
Total	<u>\$ 87,338,522</u>	<u>\$ 2,334,800</u>	<u>\$ 169,000</u>
Total East and Central	<u>\$123,401,922</u>	<u>\$11,169,100</u>	<u>\$1,851,000</u>
<u>West</u>			
Alaska	\$ 2,088,000	\$ 498,000	-
Arizona (note b)			
Colorado	1,014,284	144,760	\$ 97,500
Iowa	1,326,000	248,000	103,000
Kansas	2,070,538	163,347	50,000
Missouri	1,109,244	212,453	40,000
Montana	429,000	93,000	-
New Mexico	1,651,000	345,000	45,000
North Dakota	155,650	102,000	14,000
Oklahoma	744,000	264,000	100,000
Texas	801,000	82,000	262,000
Utah	1,714,000	180,000	189,000
Washington	2,404,000	269,000	-
Wyoming	615,599	99,317	2,000
Total	<u>\$ 16,122,315</u>	<u>\$ 2,700,877</u>	<u>\$ 902,500</u>
Grand total	<u>\$139,524,237</u>	<u>\$13,869,977</u>	<u>\$2,753,500</u>

a/Excludes expenditures for industrial development advertising.

b/State not reporting.

By the Federal Government

Numerous Federal programs are available to attract industry and promote economic development. The Department of Commerce, through the Economic Development Administration (EDA) and the regional economic development commissions, implement many of these programs. 112/ Other agencies involved in industrial development programs include the Small Business Administration and the Rural Development Program of the Farmers Home Administration. 113/

The underlying objective of EDA and the commissions is to improve the economic condition of people in depressed areas. 114/ This is attempted with a wide variety of grants, loans, and technical assistance conducive to economic growth and development. 115/

There are eight multi-State regional economic development commissions in operation which cover all or parts of 41 States. The Appalachian Regional Commission was established under the Appalachian Regional Development Act of 1965. The other seven Regional Action Planning Commissions were established by the Secretary of Commerce under the provisions of Title V of the Public Works and Economic Development Act of 1965, as amended. 116/

To the extent that the Appalachian Regional Commission's efforts toward economic diversification are successful, the economic impact of future coal busts should be cushioned. 117/

The primary goals of the Appalachian Regional Commission are

- to furnish every person in the region with the health and skills needed to compete in everyday life and
- to attract new industry and manufacturing, thus creating more employment and a more diversified economic base and self-sustaining economy. 118/

In order to achieve these goals, Appalachia needs an adequate transportation system, community facilities (sewers, water, solid waste disposal systems, housing, and related amenities), schools, and hospitals. Commission investments have been in transportation, health and child development, education, community facilities, housing, energy, environment, natural resources, research, and technical assistance. 119/

According to the Commission's economic indicators, the region's economy has been improving since 1965. 120/ The improvement has been as a result of expansion of the Appalachian economy into a variety of new industrial activities as well as growth in its traditional economic bases--coal and manufacturing. 121/ Industrial park development, for example, has proven a successful means of diversifying and promoting industrial growth in central Appalachia as well as other parts of the country. 122/ Analysis of certain economic and social trends in the region since 1965 indicate that substantial improvement has occurred in such areas as employment, per capita income, health education, and housing, although Appalachia still lags behind national trends in many of these areas. 123/

GEOGRAPHIC DIFFERENCES OF THE EFFECTS OF COAL DEVELOPMENT

Each coal region in the country will derive economic benefits and incur socioeconomic costs from increased coal development. The net benefits to the areas will differ widely, as we have seen. It appears that the Central and Eastern coal regions will derive the greatest net benefits because of their high unemployment and depressed economies. Furthermore, the social costs of increased production will be greater in the West.

Effects of increased coal development in the Central and Eastern Regions

In 1976 the average unemployment rate for the Central and Eastern coal producing counties was 7.5 percent and involved 357,471 people. There are also a large number of unemployed in nearby population centers, such as Pittsburgh, Pennsylvania; Birmingham, Alabama; Youngstown, Ohio; and Charleston, West Virginia.

Increased coal development offers an opportunity to accelerate the economic development of these areas. The economic situation should improve as new jobs are created and the high unemployment rate drops. This is an important step toward eliminating the socioeconomic problems which these areas have experienced. Furthermore, the need for Federal economic development programs, such as the Appalachian Regional Commission, may be reduced as the economic situation improves.

Since coal mining is a well established industry in the Central and Eastern regions, its expansion should not have as serious social consequences as in the West. When coal was first developed in the East, it disrupted the self-contained agrarian lifestyle and displaced the older community structure. The major social transformations from coal development may have already occurred. Through proper planning, the additional coal miners should not radically affect the way of life in the traditional coal areas of the East.

Some communities may not be able to accommodate a rapid population influx without substantially improving their facilities and services. This is particularly a problem to many eastern communities that are having difficulty alleviating present socioeconomic problems. These communities may have trouble meeting the additional infrastructure requirements of an increased population.

Effects of increased coal development in the West

Many Western States are large and sparsely populated, making it difficult to provide quality services to all residents. Revenues from coal development could improve the provision of State services, thereby benefiting the entire State.

A properly coordinated and phased program of development, which includes some industrial diversification, could provide stable long-term employment for the populations.

Socioeconomic effects are of particular concern to sparsely populated areas, such as those in the West. Many of the existing communities will not be able to absorb the new population without constructing additional public facilities. If facilities and services are not available when the population arrives, the quality of life will suffer. Since these communities are small and homogeneous, their social profile and way of life will change.

SUMMARY

Increased coal development means an influx of people into coal areas. The newcomers will need public facilities and services. The problem is that the revenue needed to pay for increased facilities and services will not become available until coal-fired powerplants and coal mines go on the tax rolls and residents become taxpaying citizens. To meet this time lag problem, communities need advanced financing. They also need timely and accurate information if they are to plan adequately for expansion.

Rock Springs and Green River in Sweetwater County, Wyoming, are examples of what happens to communities that are unprepared and underfinanced to cope with rapid population increases. Public facilities for health care, schools, recreation, sewage, and traffic were unable to keep up with demand.

Local government infrastructure costs due to increased coal development might run as high as \$4.4 billion between 1974 and 1985, and \$14.9 billion between 1974 and 2000.

Some portions of these socioeconomic costs may be beyond the immediate means of many communities. Some States (Wyoming and Montana, for example) have enacted legislation intended to mitigate these socioeconomic costs. The Federal Government has provided limited assistance.

Regardless of whether Federal assistance is expanded or not, the efficiency and effectiveness of Federal aid to affected communities probably would be increased if one agency were made responsible to coordinate the Federal role.

The West will probably experience a more significant population increase than either the Midwest or Appalachia, and will probably experience more severe social change than the Midwest or Appalachia as a result. Most of these small, homogeneous western communities are in a poor position to deal with the rapid growth. The social changes these communities will undergo are a tradeoff for increased coal development.

It appears that the Central and Eastern regions will derive the greatest net benefits from increased coal development because of their high unemployment and depressed economies.

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CHAPTER 8

WHAT IS THE UNITED STATES POSITION

IN THE WORLD COAL MARKET?

The United States has more than 25 percent of the world's coal, and is the world's largest coal producer and exporter. The Soviet Union, the People's Republic of China, and Poland are major producers; the Soviet Union and Poland are also major exporters. Japan and the European Economic Community (EEC) nations are major importers of coal.

Traditionally, the United States has exported between 9 and 11 percent of its annual bituminous coal production, which in 1975 contributed \$3.3 billion to its balance of payments. The United States exported 65.7 million tons of coal in 1975, of which 50.6 million tons (77 percent) was used metallurgically by foreign steel manufacturers. Japan, the EEC nations, and Canada purchased over 86 percent of U.S. coal exports in 1975.

Future U.S. coal exports will be used chiefly in foreign steel production. Despite stronger competition from other exporting nations, U.S. exports of metallurgical coal are expected to increase to between 55 and 61 million tons in 1985 and to between 70 and 77 million tons in the year 2000. Except for exports to Canada, U.S. exports of steam coal used by foreign utilities to produce electricity are not competitive, and are expected to increase only slightly.

The quality of U.S. metallurgical coal is one of the highest in the world, and both domestic and foreign steel producers want to use it in their coke-making processes. Supplies of metallurgical coal are limited, and data on its production, use, and export have not been routinely collected by the Bureau of Mines. This has led to some controversy concerning exactly how much is produced and exported and whether these exports will unfavorably affect U.S. steel production.

Foreign investment in the U.S. coal industry is minimal. U.S. coal companies that are wholly owned or partly financed by foreign companies accounted for 4.4 percent of total 1973 U.S. production. Foreign companies invest in the U.S. coal industry to assure security of supply and because the industry is profitable. They also seek secure sources of supply by entering into long-term purchasing contracts with U.S. exporters.

Since 1960 EEC nations have depended less on domestic coal and more on imported oil to meet their energy needs. EEC energy plans for 1985 call for a large increase in the use of nuclear power and only a slight increase in the use of coal. However, there is some doubt that the nuclear goal will be met, and any shortfall will probably be made up by increased use of natural gas and imports of oil rather than increased use of coal. The United States is expected to continue as one of the EEC's major suppliers of metallurgical coal.

In our discussions with officials in Europe, we found that coal was generally thought of as a resource of the past and a resource with use problems, whereas nuclear power is thought of as a resource of the future. Economic considerations may also be important. Coal production in the EEC is beset with problems, including high costs; increased coal use (except in the United Kingdom and Federal Republic of Germany) would mean large amounts of imports, causing dependence on foreign energy sources. Despite the need to import uranium, EEC nations have the capability of using nuclear power to meet some of their own energy needs while, at the same time, developing an industry--nuclear reactors.

Japan currently depends heavily on imports of oil to meet its energy needs. Imported oil is expected to become relatively less important between now and 1985, with nuclear power becoming more important. Coal will probably continue to meet about 12 percent of Japan's energy requirements and as energy requirements grow, coal imports will have to increase. Because of greater competition, however, U.S. coal exports to Japan are expected to increase only slightly.

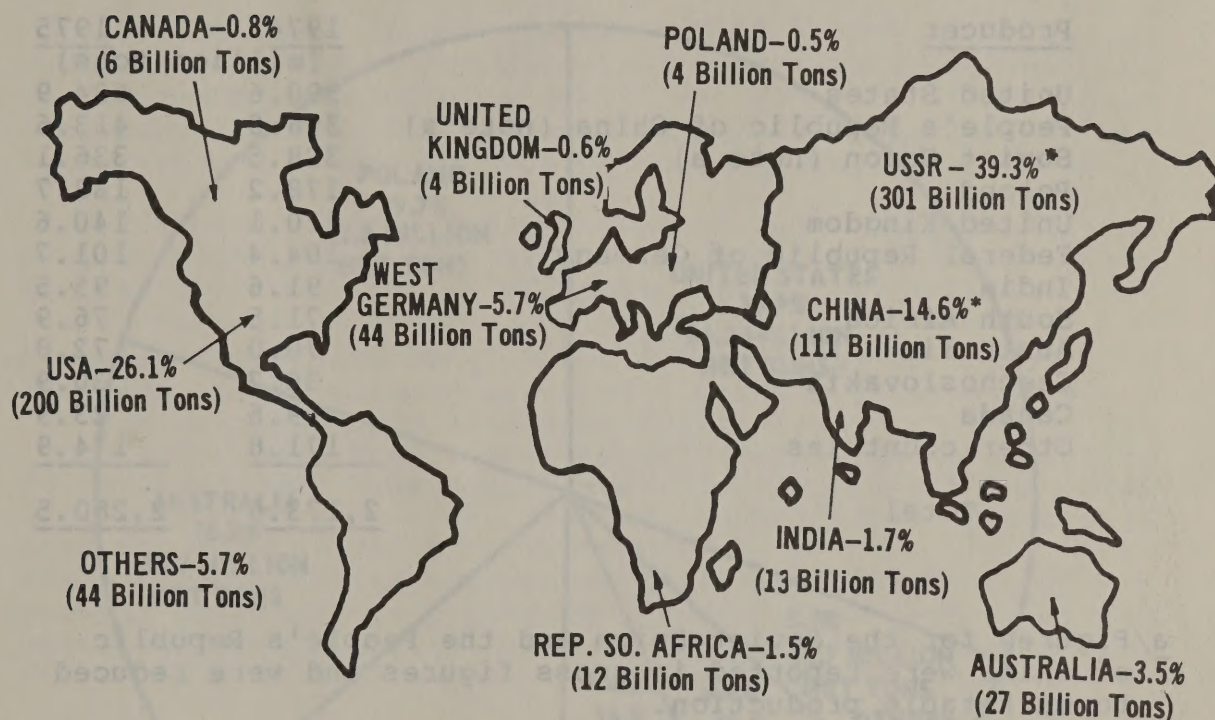
WORLD COAL

Reserves and production

According to the 1974 World Energy Conference Survey of Energy Resources, the United States has 26.1 percent of the world's economically recoverable coal reserves. Chart 1

shows worldwide distribution of recoverable coal reserves, which total 765 billion tons.* 1/

CHART 1
WORLD RECOVERABLE COAL RESERVES



*In this chapter, the word "ton" refers to net or short tons. The estimate of 200 billion tons shown by this source for the United States is probably low. See chapter 3, which estimates the U.S. reserves to be 256 billion tons.

Note: Numbered footnotes to ch. 8 are on pp. 8.30 to 8.33.

In 1975 approximately 2.3 billion tons of hard coal (bituminous and anthracite) were produced worldwide, of which 60.3 percent was produced by the United States, the Soviet Union, and the People's Republic of China.

Marketable hard coal production for 1974 and 1975 is shown in table 1. 2/

Table 1

Hard Coal Production

<u>Producer</u>	<u>1974</u>	<u>1975</u>
	(million tons)	
United States	590.6	624.9
People's Republic of China (note a)	396.0	413.6
Soviet Union (note a)	328.5	336.1
Poland	178.2	188.7
United Kingdom	120.1	140.6
Federal Republic of Germany	104.4	101.7
India	91.6	95.5
South Africa	71.5	76.9
Australia	70.0	72.8
Czechoslovakia	30.7	30.9
Canada	19.6	23.9
Other countries	<u>171.8</u>	<u>174.9</u>
Total	<u>2,173.0</u>	<u>2,280.5</u>

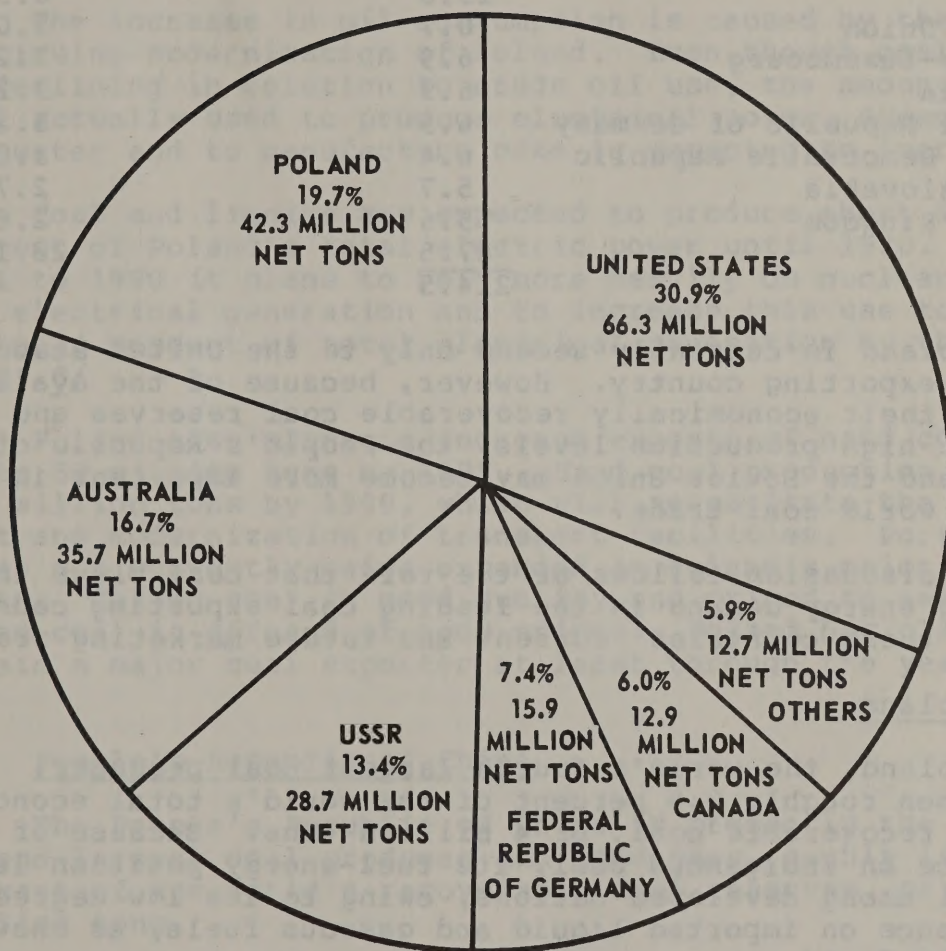
a/Figures for the Soviet Union and the People's Republic of China were reported in gross figures and were reduced to marketable production.

BOM has projected that, by the year 2000 the United States, the Soviet Union, the People's Republic of China, Poland, and India will be the principal coal producers. 3/

Principal exporters and importers

In 1975, six countries accounted for 94.1 percent of the 214.5 million tons of hard coal exported and other countries accounted for only 5.9 percent. 4/

CHART 2
PRINCIPAL WORLD COAL EXPORTS
BY COUNTRY, 1975



The countries that imported this coal are shown in table 2. 5/

Table 2
Principal World Coal Imports
By Country (1975)

<u>Country</u>	<u>Tons</u> (million)	<u>Percent of</u> <u>world imports</u>
Japan	68.5	31.9
France	19.1	8.9
Canada	16.8	7.8
Italy	13.6	6.3
Soviet Union	10.7	5.0
Belgium-Luxembourg	6.9	3.2
Bulgaria	6.9	3.2
Federal Republic of Germany	6.9	3.2
German Democratic Republic	6.4	3.0
Czechoslovakia	5.7	2.7
United Kingdom	5.6	2.6
Others	47.5	22.1
	<u>214.5</u>	

Poland is currently second only to the United States as a coal-exporting country. However, because of the availability of their economically recoverable coal reserves and current high production levels, the People's Republic of China and the Soviet Union may become more important in future world coal trade.

A discussion follows of the role that coal plays in meeting energy demand in the leading coal exporting countries and of these countries' current and future marketing prospects.

Poland

Poland, the world's fourth largest coal producer, possesses roughly 0.5 percent of the world's total economically recoverable coal, or 4 billion tons. Because of its reliance on indigenous coal, its fuel-energy position is unusual among developed nations, owing to its low degree of dependence on imported liquid and gaseous fuels, as shown in table 3. 6/

Table 3

Distribution of Primary Energy Supply

	<u>1970</u>	<u>1975</u>	<u>1980</u>
	----- (percent) -----		
Coal	82.3	76.5	69.3
Oil	10.1	14.2	20.6
Natural gas	6.0	7.8	9.0
Hydropower	0.6	0.4	0.3
Other	1.0	1.1	0.8

The increase in oil consumption is caused by the continuing modernization of Poland. Even though coal use is declining in relation to crude oil use, the amount of coal actually used to produce electrical power, steam, and hot water and to manufacture coke is expected to increase. 7/

Coal and lignite are expected to produce about 95 percent of Poland's total electric power until 1980. From 1981 to 1990 it plans to rely more heavily on nuclear power for electrical generation and to increase this use to 12 to 14 percent of total electrical generation by the year 2000. 8/

Poland also plans to increase exports of hard coal to 45 to 50 million tons by 1985. Hard coal production may reach 276 million tons by 1990, which will necessitate the development and modernization of transport facilities. Port facilities are currently being expanded in Poland's major Baltic ports. Coking coal is good quality and priced to sell, and steam coal is offered at good prices. Poland has planned to remain a major coal exporter at least through the year 2000. 9/

People's Republic of China

The People's Republic of China is presently the world's second largest coal producer and possesses roughly 14.6 percent of the world's recoverable coal reserves, or 111 billion tons.

In 1952 coal accounted for 96 percent of China's total energy supplies, but by 1974 it had declined to 68 percent. This was offset by increased use of oil and natural gas during the same period. Production projections of coal, oil, natural gas, and hydroelectricity, which assume further substitution of oil for coal, are shown in table 4. 10/

Table 4

	<u>Total Energy Production</u>			
	<u>Coal</u>	<u>Oil</u>	<u>Gas</u>	<u>Hydroelectricity</u>
	----- (percent) -----			
1974	67	23	9	1
1980	51 - 63	26 - 35	10 - 13	1

Even though the percent of coal used to produce energy is decreasing, coal production has increased from an average of 286 million tons during 1967-1971 to 413.6 million tons in 1975. 11/ This indicates a growth in China's economy, because its coal exports are minimal.

The Chinese are interested in the use of nuclear power to generate electricity. In 1972 and 1973 they sent industrial survey teams of power and nuclear specialists to Japan and Canada. However, nuclear power is not expected to be a significant factor in energy production before 1985. 12/

Priority is being given to the development of large coal resources for internal steel and energy requirements and for future export. China exported 447 thousand tons of coal to Japan in 1974 and hopes to expand its exports. 13/ Its coal industry already compares in size with that of the United States and the Soviet Union, and its annual output of marketable coal may reach 560 million tons by 1985. The coking coals are generally of good quality. 14/

China has the potential of becoming an important coal exporter. However, coal production centers, and possibly a port, must be developed. 15/ China lacks foreign currency for purchasing capital equipment and has a shortage of mining machinery. 16/

Soviet Union

The Soviet Union currently ranks as the world's third largest coal producer and possesses roughly 300 billion tons of recoverable coal, 39.3 percent of the world's total.

The 1976-80 Soviet 5-year plan for energy projects increased coal, oil, and natural gas production, as shown in table 5. 17/

Table 5
Soviet Energy Projections

	<u>Actual</u>			<u>1975</u>		<u>1980</u>
	<u>1972</u>	<u>1973</u>	<u>1974</u>	<u>Planned</u>	<u>Estimated</u>	<u>Planned</u>
----- (million tons) -----						
Raw coal (all ranks)	697.4	717.2	737.0	764.5	770.0	869 to 891
Marketable hard coal	a/ 313.2	a/ 320.2	a/ 328.5	-	b/ 336.1	c/ 384 to 394
Crude oil	434.5	471.9	507.1	545.6	539.0	682 to 704
----- (billion cubic meters) -----						
Natural gas	229.0	250.0	280.0	320.0	285.0	400 to 435
----- (billion kilowatt hours) -----						
Electric power (note d)	850.0	913.0	985.0	1,065.0	1,035.0	1,340 to 1,380

a/Production 1972-75 from BOM.

b/Actual 1975 marketable production.

c/Estimated on basis of actual ratios between raw coal and marketable hard coal production during 1972-75.

d/The 1976-80 projections include commissioning of 13 million to 15 million kilowatts of capacity at nuclear powerplants.

In 1960 coal accounted for 70 percent of all fuel consumed in the Soviet Union, but by 1974 this had declined to 45 percent. The combined share of oil and gas rose from 20 to 50 percent during the same period. In the current

5-year plan, coal will be used more widely in domestic power generation, primarily to save oil and gas for petrochemicals and export. 18/

Development of coal reserves will be accelerated in the next few years through construction and operation of massive deep mines and strip mines. By 1985 the annual output of marketable hard coal should reach between 440 million and 500 million tons. 19/

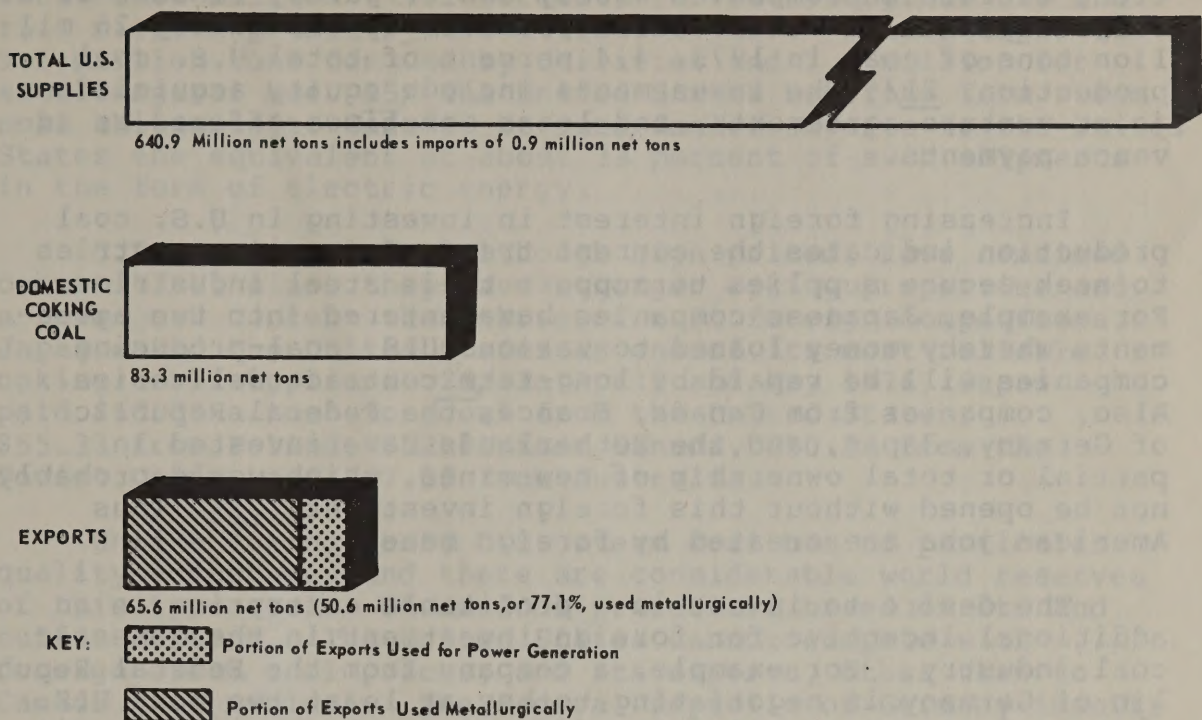
Exports are controlled only by market availability and the Soviet Union wants to expand exports to Western countries and to Japan. A new port is being constructed in the East to facilitate trade with Japan. 20/

U.S. COAL

As noted, U.S. coal exports consist primarily of metallurgical coal and thus have little impact on the supply of domestic coal for power generation. Total imports* for 1975 were only 0.94 million tons and domestic production was 640 million tons. Chart 3 illustrates domestic production, domestic coking coal use, imports, and exports in 1975.

*Imports of coal may increase in the future as the price of coal in the United States rises, making foreign coal economically attractive. A recent order for 7.7 million tons was given by a Florida utility to a coal mining company in South Africa. This decision was made after the utility found that it could purchase the low-sulfur coal at a more favorable price than could be negotiated in the United States.

CHART 3
DOMESTIC COAL USE



The majority of U.S. exports originates in the Eastern region and moves to ports or to Canada by rail. About 75 percent of all coal exports are shipped overseas out of Hampton Roads, Virginia. Lesser amounts move through Baltimore, Mobile, New Orleans, Philadelphia, and Los Angeles. Coal exporters cited a need for more railroad hopper cars and better storage facilities at the ports to facilitate movement of coal to the ports and loading of coal onto ships. Delays in transporting and processing coal ultimately increase its price, possibly damaging the competitive position of U.S. coal.

Foreign purchasers generally enter into long-term contracts (some as long as 15 years) for U.S. metallurgical coal to promote incentives for capital investment in production facilities. The contracts contain cost escalation and renegotiation provisions and rely on mutual good faith--the abilities of the U.S. producer to supply coal and of the importer to buy it. Coal exporters believe that the foreign buyers should not be made to suffer more than domestic users in the event of a supply crisis.

Foreign investment in coal industry

According to a study by the Federal Energy Administration, 15 foreign companies wholly own or partly finance 19 U.S. coal companies or mines, which produced approximately 26 million tons of coal in 1973, 4.4 percent of total U.S. coal production. 21/ The investments include equity acquisitions, joint venture agreements, and loans sometimes offered as advance payments.

Increasing foreign interest in investing in U.S. coal production indicates the current trend of foreign countries to seek secure supplies to support their steel industries. For example, Japanese companies have entered into two agreements whereby money loaned to various U.S. coal-producing companies will be repaid by long-term contract deliveries. Also, companies from Canada, France, the Federal Republic of Germany, Japan, and the Netherlands have invested in partial or total ownership of new mines, which would probably not be opened without this foreign investment. 22/ Thus American jobs are created by foreign money.

The desire to invest in a profitable enterprise is an additional incentive for foreign investment in the domestic coal industry. For example, a company from the Federal Republic of Germany is negotiating to buy at least two more U.S. coal-producing properties to add to its other operations in West Virginia and Kentucky. Its present U.S. subsidiaries produce about 2 million tons annually, most of which is being sold to U.S. steel producers under long-term contracts. 23/ Also, a British investor has purchased 25 percent of the 11th largest U.S. coal-mining corporation, which produces roughly 10 million tons of coal annually. 24/

According to U.S. coal exporters, increased foreign investment does not appear to be a matter of concern and the percent of U.S. coal production controlled by foreign interests is so small that the possibility of foreign control of domestic coal markets is unlikely.

The United States also invests in foreign coal industries. For example, a few U.S. coal companies or their parent companies control 70 to 75 percent of the Australian coal industry. There is also some U.S. investment in the Canadian coal industry.

Prospects for increased coal exports

Bituminous coal exports in 1975 totaled 65.7 million tons--50.6 million (77.1 percent) for metallurgical use and 15.1 million primarily for utilities' use. Canada imported 9.6 million tons for use by utilities and 7.2 million for metallurgical use. ^{25/} The United States benefits from steam coal shipments to Canada, because Canada exports to the United States the equivalent of about 33 percent of such shipments in the form of electric energy.

U.S. coking coals, although high priced, have remained competitive, since they have stronger coking properties and a lower ash content than those of most foreign competitors. Japan rated the United States as one of its most reliable coking coal suppliers. ^{26/} In April and May 1976, Japan paid \$63.35 a ton* for coal from the United States, \$55.33 from Poland, \$52.81 from Canada, \$50.24 from the Soviet Union, and \$47.03 from Australia.

Unlike coking coal, U.S. steam coal has no particular quality advantages and there are considerable world reserves of this type coal. Steam coal prices are based on Btu and sulfur content. The United States cannot compete with foreign steam coal prices, and its exports, other than to Canada, are minimal. The Federal Republic of Germany imports mostly steam coal and in 1975 paid \$47.64 a ton c.i.f. from the United States, \$38.11 from Poland, \$36.48 from the United Kingdom, \$27.26 from the Soviet Union, and \$25.33 from the Republic of South Africa. ^{27/} It appears, therefore, that steam coal exports overseas will remain at low levels.

Both steam and metallurgical coal exporters face vigorous competition from Poland and the Soviet Union, because those countries' pricing practices reflect overall national economic goals rather than cost factors. The People's Republic of China may also be expected to use this pricing practice, if in the future it becomes a major exporter.

European countries and Japan stress strong nuclear preferences for meeting future energy demands, since, except for the United Kingdom and West Germany, they lack coal resources. A total nuclear moratorium is considered improbable because of the desire of these countries to gain nuclear capabilities and to lessen dependence on imported oil. ^{28/}

*Includes cost of coal, insurance, and freight (c.i.f.).

U.S. coking coal exports in 1985 and beyond will depend on foreign requirements for steel. In 1975 foreign raw steel production totaled 601.6 million tons, causing a coking coal demand of roughly 476.7 million tons--0.79 tons of coking coal for each ton of raw steel produced. The United States supplied 10.6 percent, or 50.6 million tons, of this coking coal. The Coal Task Group of the National Petroleum Council and BOM estimate that (1) foreign raw steel requirements for 1985 will be 975 million tons, a growth rate from 1975 to 1985 of 4.95 percent annually, and (2) foreign coking coal needs in 1985 will be 527 million tons--0.54 tons of coking coal for each ton of raw steel produced. The decreased use of coking coal to produce raw steel assumes that future technology will reduce the amount of coke required to produce a ton of pig iron. Thus the growth rate for coking coal demand will be one percent a year between 1975 and 1985. 29/

BOM estimates that total U.S. coking and steam coal exports will be 75 million tons by 1985 (roughly 11 percent of the foreign market) and 100 million tons by the year 2000. Over the past six years, an average of 77.4 percent of exports was used metallurgically. This average, applied to the BOM projections for exports, is shown in table 6. 30/

Table 6

Export Projections

<u>Year</u>	<u>Metallurgical use</u>	<u>Steam use</u>	<u>Total exports</u>
	----- (million tons) -----		
1985	58.1	16.9	75.0
2000	77.4	22.6	100.0

According to BOM projections, metallurgical coal exports will increase at an annual rate of 1.39 percent between 1975 and 1985 and 1.93 percent between 1985 and 2000, or at an overall annual rate of 1.71 percent between 1975 and the year 2000.

A working party of the Organization for Economic Cooperation and Development reassessed the role of coal and estimated that 1985 U.S. coking coal exports will be between 55 million and 61 million tons. 31/ An official of the Coal Exporters Association estimated that such exports would be between 55 and 57 million tons in 1985 and 70 and 71 million tons in the year 2000.

Except for modifications that will result in somewhat lower coke ratios, technological changes in steel manufacturing are not expected to substantially alter demand within the next decade. Metallurgical coal is the most economical and technically satisfactory coal to use in making coke for the production of steel. Two publicized experimental processes (formed coke and direct reduction) that do not use metallurgical coal are being tested in this country, but they are not expected to be economical within the next decade. 32/

U.S. METALLURGICAL COAL IN THE WORLD MARKET

A July 28, 1976, statement on metallurgical coal by the American Iron and Steel Institute emphasized that U.S. low-volatile coal resources are limited. 33/ Coal exporters share this view but believe that the magnitude of low-volatile exports does not adversely affect domestic steel industry supplies nor seriously jeopardize U.S. reserves.

The exporters note that long-term contracts are required for financing new mines and that without export trade some mines would have to be closed. They also contend that the steel industry has assured the availability of low-volatile coal through captive mines and resources. The Institute expressed concern about the possible future use of metallurgical-type coal for power generation because of environmental constraints. It suggested that data be gathered on production, consumption, and foreign trade of premium-grade metallurgical coal by low-, medium-, and high-volatile categories.

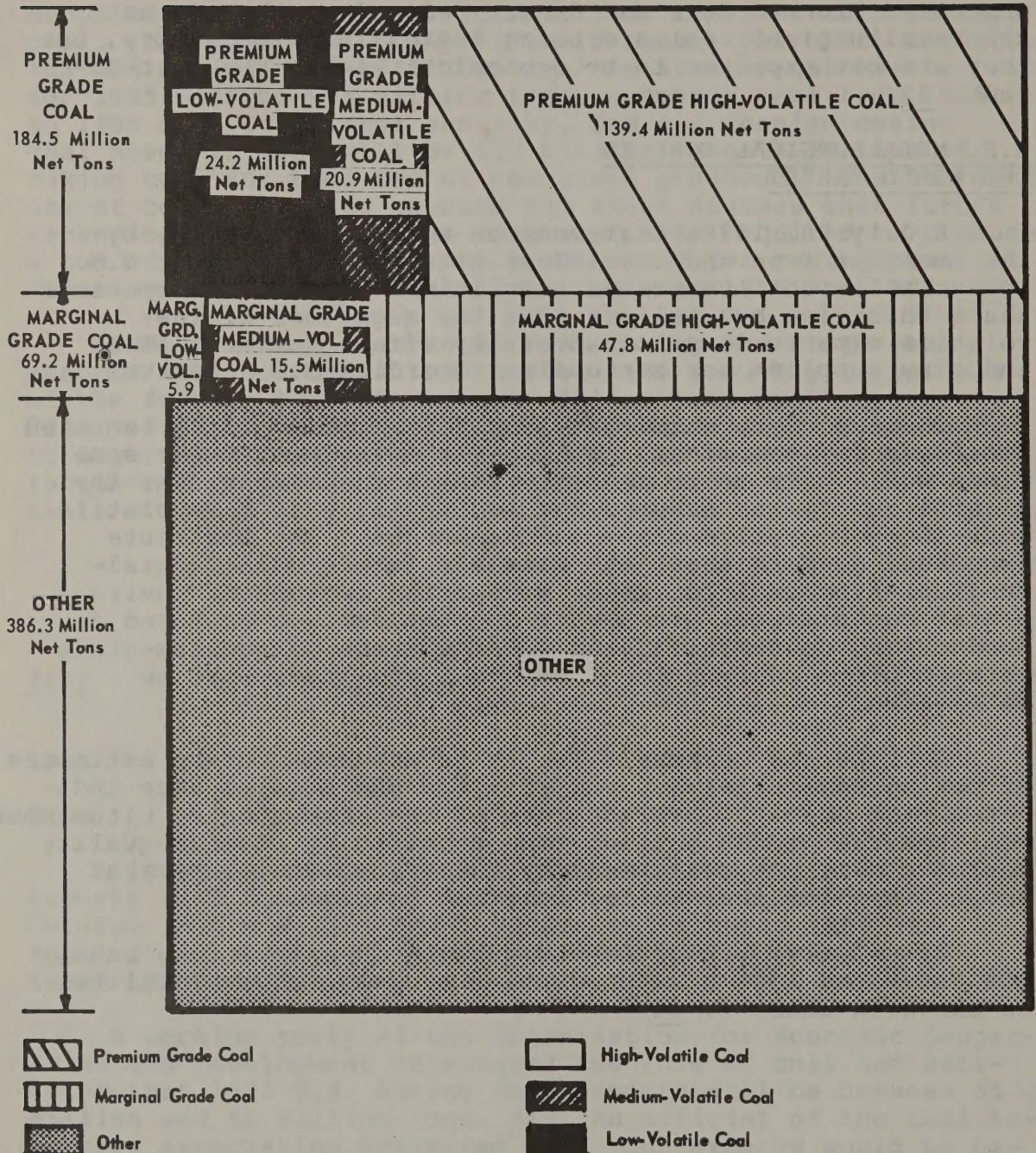
As reported on page 3.14, there are no accurate estimates of coking coal reserves, but previous BOM studies have indicated that about 20 billion tons of the demonstrated bituminous coal reserve of 233 billion tons consists of premium-quality coking coals. An assessment by the Bureau indicates that about 7 billion tons is low-volatile coking coal.

By relating production to quality in a fuel data bank, BOM estimated 1975 U.S. production by grade and volatility, as shown in chart 4. 34/

CHART 4

DIAGRAM OF 1975 U.S. PRODUCTION – SHOWING PREMIUM, MARGINAL GRADES
AND HIGH, MEDIUM, AND LOW VOLATILE COALS

1975 U.S. Production: 640 Million Net Tons



Of the estimated 30 million tons of U.S. low-volatile coking coal produced in 1975, approximately 17 million tons were used for domestic production of metallurgical coke, 4 to 5 million for electric power generation, 2 million for industrial fuel and heating, and 6 million tons for export. The end use of the remainder could not be determined. Not much low-volatile metallurgical grade coal is used domestically to generate electric power, but BOM and electric power officials note that, in addition to steam grade coal, higher volatilities of premium- and marginal-grade coking coals are used for this purpose. 35/ Higher categories of coking coal are generally not used for power generation due to their higher price and the limited flexibility of utility boilers regarding the type of coal they can burn.

BOM estimates coking coal exports from fragmentary data supplied by shippers and consumer country reports. Most countries and private companies have varying classifications of coal but none report on the volatile matter content of imported coal. The high-, low- and medium-volatile coal classifications of the BOM are of academic interest only, since the use of company name brands and the mixing of coals before shipping is the usual practice. The volatile matter and ash content and other elements of the coal analysis are determined to ascertain conformance to contract specifications and are precisely known only by the shipper and the purchaser. These specifications vary from purchaser to purchaser and do not usually coincide with BOM criteria. Thus BOM contends that no precise data is reported for low-volatile coal and that, in the absence of identical standards for volatility, estimates of low-volatile bituminous coal exports cannot be made with certainty. 36/

Our report of April 14, 1976, (B-178205) stated that the Federal Energy Administration was not fully complying with a congressional mandate to maintain information on coal exports. The President of the Coal Exporters Association of the United States, Inc., suggested that the Shipper's Summary Export Declaration, now filed with the Department of Commerce, be amended to report whether exported coal is of steam or metallurgical grade, and, if metallurgical grade, whether it is low-, medium or high-volatile as defined by American Society for Testing and Materials standards. In commenting on this report, FEA stated that they had reached agreement with the Department of Commerce for a system for collecting information on coal exports. The new system should be in operation shortly.

Exports

The United States exports primarily bituminous coal. Anthracite exports (primarily to Canada and the EEC) and lignite exports totaled only 1.4 percent of U.S. coal exports in 1974. Bituminous coal exports have consisted of over 77 percent metallurgical coal since 1973 (see table 7). 37/ This figure was somewhat inflated in 1974, when some nations faced the possibility of shortages of metallurgical grade coal and bought lower grade coal for metallurgical use.

Table 7

Destination of U.S. Bituminous Coal Exports by Use

	1973		1974		1975		
Destination	Metal- lurgical use	Total exports	Metal- lurgical use	Total exports	Metal- lurgical use	Total exports	Percent of total 1975 exports
	----- (thousand tons) -----						
Canada	7,733	16,231	7,488	13,706	7,168	16,735	25.5
Latin America	2,946	2,963	2,761	2,761	3,728	3,801	5.8
European Economic Community:							
Belgium/ Luxembourg	1,205	1,205	1,109	1,109	627	627	1.0
France	1,866	1,866	2,510	2,510	1,735	3,583	5.5
West Germany	32	1,632	49	1,484	50	1,989	3.0
United Kingdom	895	941	915	1,405	888	1,888	2.9
Italy	3,192	3,294	3,786	3,903	4,410	4,493	6.8
The Netherlands (note a)	1,780	1,780	2,545	2,545	2,092	2,093	3.2
Total EEC	8,970	10,718	10,914	12,956	9,802	14,673	22.3
Other European Countries	3,534	3,534	2,899	2,899	4,180	4,498	6.9
Japan	19,190	19,190	b/27,346	27,346	25,423	25,423	38.7
Other	234	234	258	258	319	537	0.8
Total	42,607	52,870	51,666	59,926	50,620	65,667	100.0
Metallurgical use of total bituminous coal exports (percent)	80.6		86.2		77.1		

a/ Includes some tonnage transshipped to other European countries.

b/ Includes some tonnage not customarily classified as metallurgical coal.

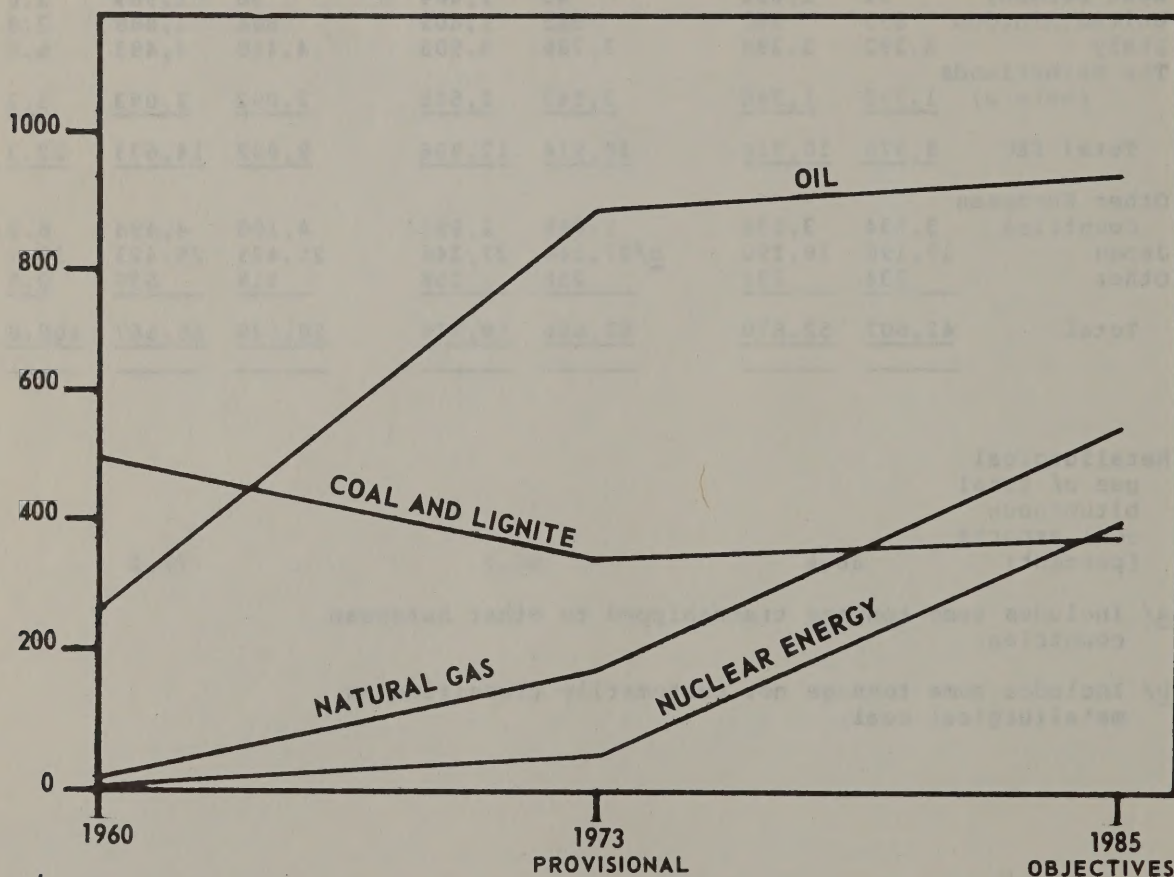
COAL USE IN THE EUROPEAN ECONOMIC COMMUNITY AND IN JAPAN

European Economic Community

The use of coal as a source of energy has declined in the EEC* since 1960, because domestic coal production has become more difficult and costly. As shown below, 1985 objectives of the EEC Commission, the Community's administrative body, show that the primary emphasis will be placed on oil and natural gas, with coal and nuclear energy providing about the same, but smaller, levels of energy input. 38/

CHART 5
PRIMARY ENERGY REQUIREMENTS (note a)

tons of coal equivalent (note b)



a/ Includes requirements for power generation, steelmaking and all other uses.

b/ One ton coal equivalent equals 2.8×10^7 Btu.

*Belgium, Denmark, Federal Republic of Germany, France, Ireland, Italy, Luxembourg, the Netherlands, and the United Kingdom.

In 1975 EEC produced 275.7 million tons of coal, 12.1 percent of the world total. Average production during 1967-71 was 361.9 million tons, 17.8 percent of the world total. The Netherlands' coal industry has been completely phased out. Belgium, the United Kingdom, the Federal Republic of Germany, and France are the only remaining major EEC coal producers. 39/

EEC mines in general are old and nearly depleted. Difficult mining conditions have led to high costs and low productivity despite mechanization. From 1970 to 1974, average output per worker per shift in underground mines remained at about 3.9 tons while the number of miners decreased from 439,000 to 341,000. 40/ Many mines have been kept open primarily to provide employment in economically depressed areas.

The EEC imported 39 percent of its energy in 1963. By 1973 it was importing 61 percent, primarily because imports of crude oil almost tripled from 1963 and coal production decreased 37 percent. At the same time, production of natural gas increased by a factor of 10. 41/

Thus in 1973 the EEC depended on imported oil for about 56 percent of its energy needs. 42/ EEC nations are now attempting to lessen this dependence by stressing the development of nuclear power and North Sea oil and gas fields and by providing for a modest increase in coal production from its 1973 level.

Future energy requirements

The EEC Commission's "Medium-term guidelines for coal 1975-1985," dated November 21, 1974, stated that the events of 1973 demand that the EEC reduce dependence on imported energy and that coal should continue to play a role in generating electricity and making steel for a long time. 43/

Commission energy goals for the year 2000 anticipate nuclear and gas to supply 50 percent and 33 percent, respectively, of the total energy needs. To accomplish these goals:

- Nuclear power station construction would have to be accelerated so that by 1985 nuclear power would supply half the electricity requirements.
- Indigenous and imported supplies of natural gas must be increased and used optimally.

--Consumption of coal and lignite must be raised above current levels, calling on increased production and imports.

The Commission quantified these goals as follows, based on planning goals of the EEC members. These goals are not binding but are intended as policy guides. 44/

Table 8

Primary Energy Requirements of the EEC

	<u>1960</u>	<u>1973</u> <u>provisional</u> <u>(percent)</u>	<u>1985</u> <u>objectives</u>
Solid fuels	60.0	22.6	16
Oil	33.0	61.4	41
Natural gas	1.7	11.6	24
Hydroelectric power, etc.	5.2	3.0	2
Nuclear energy	0.1	1.4	17

Projections for solid fuel use in 1985, by market, are shown in table 9. 45/

Table 9

Solid Fuel Use in the EEC

	<u>1973</u> <u>(million tons coal equivalent)</u>	<u>1985</u>
Hard coal:		
Power stations	119	149
Coking plants	107	115
Other markets	<u>64</u>	<u>40</u>
	290	304
Other solid fuels	<u>35</u>	<u>53</u>
Total	<u>325</u>	<u>357</u>

To meet this modest increase in coal use with little increase in domestic production, imports would have to increase from 33 million tons in 1973 to 55 million tons in 1985 (1975 imports were 44 million tons). Poland and the United States are expected to continue as the major exporters to EEC, but, as discussed before, the U.S. market share would probably be mostly limited to coking coal. 46/

To compare overall EEC objectives with individual country plans, we spoke with government and steel, coal, and electrical industry officials in the United Kingdom, Federal Republic of Germany, France, and Belgium. These officials, except for those in the United Kingdom, agree with the Commission view that domestic production will increase only slightly in the next 10 years. They do not agree that there will be an increase in steam coal consumption and, thus, a need for increased imports.

In our discussions, we found that coal is generally thought of as a resource of the past and a resource with usage problems, whereas nuclear power is thought of as a resource of the future. Economic considerations may also be important. Coal production in the EEC is beset with problems, including high costs, and increased coal use (except in the United Kingdom and Federal Republic of Germany) would mean large amounts of imports, causing dependence on foreign energy sources. Despite the need to import uranium, EEC nations have the capability to develop nuclear power to meet some of their energy needs while at the same time, giving them an export industry--nuclear reactors and other equipment.

Federal Republic of Germany

Government officials in the Federal Republic of Germany plan for coal production to remain constant at 1973 and 1974 levels. Among the measures taken to stimulate use of domestic coal and reduce rising dependence on foreign oil are (1) a law generally prohibiting the construction of new oil- or gas-fired electrical generating plants, (2) an import quota of about 6 million tons of coal a year, and (3) subsidies to the coal industry amounting to \$3.20 (in 1975) per ton of production. The goal is to be more than self-sufficient in coal up to the year 2000.

The use of coal in total energy needs will remain constant to the early 1980s, when nuclear power is expected to begin replacing steam coal for electrical generation. Nuclear power is projected to meet 40 percent of the electrical demand in 1985, but the forecast may be revised downward. An increase in EEC steel production and the resultant demand for coking coal may balance the decreased domestic demand for steam coal as existing coal-fired power stations are phased out.

Energy consumption goals for 1985 are shown in table 10. 47/

Table 10

West German Energy Consumption

	<u>1973</u>	<u>1985</u>
	(percent)	
Oil	55	44
Hard coal and lignite	31	21
Natural gas	10	18
Nuclear energy	1	15
Other	3	2

Small amounts of coal are currently imported, mostly for use by utilities. Since it has an excess supply of coal, officials do not expect an increase of steam coal imports.

West German steel producers are obligated, by agreement, to buy only West German coking coal, if available. Coal producers do not anticipate domestic coking coal demands to increase, despite increased demand for steel through 1985, because of technological changes in the steelmaking process. The domestic supply of coking coal should more than meet demand.

The United Kingdom

The United Kingdom plans to expand coal production to about 145 million tons by 1985, but coal use as a percent of total energy consumption is expected to decrease slightly. Further expansion is expected at least to the year 2000. Increased coal production and consumption is an integral part of its goal of energy self-sufficiency. Energy demand goals for 1985 are shown in table 11. 48/

Table 11

British Energy Demand

	<u>1973</u>	<u>1985</u>
	(percent)	
Oil	49.9	44
Hard coal and lignite	35.3	31
Natural gas	11.2	18
Nuclear energy	3.2	7
Other	0.4	-

The United Kingdom currently has an excess capacity for power generation and is not overly concerned about nuclear power. Coal is seen as a more feasible source of power in the near future. Nuclear power will be more important beyond 1985.

Reserves of oil and natural gas in the North Sea are expected to reap economic benefits amounting to almost 8 percent of the gross national product by 1985. 49/ British North Sea oil production is expected to be about 2 million barrels a day in 1980, which, as a comparison, is equivalent to about one-eighth of current U.S. oil consumption. The oil will be used for domestic and export purposes. It is expected to have little effect on steam coal use.

British officials expect that domestic production of steam coal will meet needs for the next several years and also allow about 3 million tons for export.

Steel production is expected to increase through 1985. Government officials believe that demand for coking coal will remain constant because of technological advances, but steel industry officials see coking coal needs increasing by 25 percent over current needs. The United Kingdom has large reserves of coking coal but must import two to three million tons of high-quality coking coal a year. Government officials see no additional demand for coking coal imports, whereas steel industry officials do. The United States is currently the United Kingdom's largest metallurgical coal supplier and is expected to remain so, despite the fact that some British officials feel that the United States is not always a reliable supplier.

France and Belgium

The small coal industries in France and Belgium survive only with heavy government subsidies. Belgian officials say that coal production in Belgium will remain at current levels through 1985. Production in France is expected to decline. Nuclear power is expected to play a large role in meeting both nations' electrical power needs by 1985, but levels of nuclear production are uncertain.

Both countries will have to import steam coal until their nuclear goals are met. Neither country currently imports much U.S. steam coal nor are they expected to do so in the future.

Coking coal requirements in both nations are expected to remain constant through 1985 and most will have to be imported. The United States will probably remain an important supplier.

Japan

Due to Japan's limited domestic resources and dependence on overseas supplies, the Ministry of International Trade and Industry has formulated a new energy policy for Japan. The new policy's basic premise is that slowing Japan's rate of economic growth will slow the accompanying energy demand. Japan intends to shift its long-range economic emphasis from massive energy-consuming industries* to low energy-consuming, labor intensive industries in order to promote more efficient use of energy. 50/

Projected energy demand and supply are shown in table 12. 51/

*One major effort will be to shift ore conversion facilities (i.e., aluminum, copper) to the ore-producing country. This decision may portend a future trend by those countries that are heavy importers of raw ores.

Table 12

Japanese Energy Demand and Supply

	<u>1973</u>	<u>1980</u>	<u>1985</u>
	----- (percent) -----		
Hydropower	4.7	4.2	3.7
Geothermal energy	0.0	0.1	0.5
Domestic petroleum and natural gas	0.9	1.2	1.8
Domestic coal	3.8	2.5	1.9
Nuclear power	0.6	4.4	9.6
Imported liquified natural gas	0.8	5.2	7.9
Imported coal	11.8	13.4	11.2
Imported petroleum	77.4	68.9	63.3

Despite some domestic opposition to nuclear powerplants, Japan's use of nuclear power is projected to increase from 0.6 percent in 1973 to 9.6 percent in 1985, which will represent roughly 26 percent of total electric power production. 52/

Coal is expected to remain important in Japan, but will be used primarily for steel production, as shown in table 13. 53/

Table 13

Japanese Coal Use

	<u>1973</u>		<u>1980</u>		<u>1985</u>	
	<u>Amount</u>	<u>Percent</u>	<u>Amount</u>	<u>Percent</u>	<u>Amount</u>	<u>Percent</u>
	<u>(million</u>	<u>of</u>	<u>(million</u>	<u>of</u>	<u>(million</u>	<u>of</u>
	<u>tons)</u>	<u>energy</u>	<u>tons)</u>	<u>energy</u>	<u>tons)</u>	<u>energy</u>
Domestic coal	23.8	3.8	22.0	2.5	22.0	1.9
Imported coal	63.8	11.8	101.2	13.4	112.6	11.2
(Portion- steam coal)	<u>(0)</u>	---	<u>(5.2)</u>	---	<u>(16.1)</u>	---
Total	<u>87.6</u>	<u>15.6</u>	<u>123.2</u>	<u>15.9</u>	<u>134.6</u>	<u>13.1</u>

Australia, the United States, and Canada will continue to be Japan's principal coal sources, but by 1980 Australian and Canadian coal is expected to account for a slightly bigger share of Japan's total coal imports, while the United States' share decreases by about 10 percent. Imports from the Soviet Union, the People's Republic of China, and Poland are expected to increase. 54/ Thus, the United States will face increasing competition in the Japanese coal market.

Views of the International Energy Agency

The Secretariat of the International Energy Agency (IEA)*, the IEA's administrative body, has expressed doubts about the energy projections of its members. A discussion paper, dated June 8, 1976, stated in part that:

--A special IEA study gives reason to believe that the Agency's nuclear capacity will be significantly below member projections for 1985.

--Oil and natural gas are limited in quantity and, worldwide, the present generation faces the probable end of the oil era.

--New technologies (e.g., solar power) are unlikely to produce energy on a major scale before 1990 or later.

The Secretariat believes that, for these reasons, there should be a serious and sustained reexamination of coal and that the subject should receive no less attention than nuclear power. 55/ It had stated earlier that, unless more coal and the facilities to use it are available, any nuclear shortfall may have to be offset with additional amounts of imported oil. 56/

*The IEA, established in November 1974, consists of 18 members of the Organization for Economic Cooperation and Development, including all EEC nations (except France), the United States, Canada and Japan. Its purpose is to promote cooperation in energy matters among its members, other oil-consuming nations, and oil-producing nations.

It seems logical that the IEA would prefer its members to use more coal and less oil. A primary objective of the IEA is to reduce its members' dependence on imported oil. IEA members produced slightly over one-third of the world's coal in 1974, an amount only slightly below their demand. However, they produced about 20 percent of world production crude oil, an amount equal to only 40 percent of their demand.

This reasoning may appear less logical to the Agency's EEC members. Five of them produce almost no coal at all and the three that do see production problems and lack of demand as major hindrances to expanded coal production.

SUMMARY

The United States is the largest producer and exporter of coal in the world. Despite stiffer competition, especially from the Soviet Union and Poland, in the years to come, the United States should continue to do well in the world coal market due to the high quality of its metallurgical coal.

In 1975, United States coal exports made a positive contribution of \$3.3 billion to the Nation's balance of payments. In that year, 77 percent of the United States coal exports were metallurgical coal to foreign steel manufacturers.

Metallurgical coal exports are expected to increase at an annual rate of 1.71 percent between the present and the year 2000. Exports of United States steam coal, which is less competitive, are expected to increase more slowly than metallurgical coal exports. Historically, the United States exports from 9 to 11 percent of its annual bituminous coal production.

Whether the continued export of metallurgical coal will adversely affect domestic steel manufacturers in the future is a matter of dispute. Better data are needed concerning the size and characteristics of metallurgical-grade coal deposits in the United States.

Foreign investment in the United States coal industry accounted for about 4.4 percent of total production in 1973 and is not considered a policy problem.

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CHAPTER 9

WHERE DO WE GO FROM HERE?

Fifty years ago coal provided 80 percent of the Nation's energy; 25 years ago 38 percent; in 1976 about 19 percent; but renewed interest is emerging. The renewed interest in coal as an energy source is a matter of necessity rather than choice. If it were strictly a matter of choice, coal's decline relative to other fuels would continue. Coal would not be chosen over oil and gas for several basic reasons: coal is mined rather than pumped and therefore is more dangerous and difficult to extract from the earth; it is bulkier and therefore more difficult to transport and to handle; and it is dirtier and therefore causes more pollution when burned.

Today, in order to meet its increasing demand for oil, the United States must import ever larger quantities. Despite a quadrupling of oil prices in the past four years, the United States' dependency on oil imports has grown from 35 percent of total oil consumption to about 50 percent during the especially cold months of January and February 1977. And unless action is taken by the Federal Government, this dependence on foreign oil will continue to grow. During 1976 the United States imported 7 million barrels of oil per day (9 million during the months of January and February 1977) and this could rise to 11.5 million by 1985. Domestic oil reserves are no longer adequate to meet demand. In the case of natural gas, domestic reserves are actually declining and have not been able to meet demand for several years.

Domestic coal resources, in contrast, are very abundant. Indeed, coal reserves represent 90 percent of the Nation's total fossil fuel reserves. It is no wonder, therefore, that coal is being turned to as one of the major solutions (along with energy conservation) to the oil and gas problem. Coal may be dirty, bulky, and costly to extract, but there is a lot of it. The same can no longer be said for domestic oil and gas resources when they are compared with the Nation's rate of consumption.

The purpose of this study has been to assess the extent to which coal can relieve the Nation's oil and gas problem, and the costs to society for this particular solution.

Our overall observations are that:

- The probability that coal will relieve the oil and gas supply problem is very slight through 1985. Whether this probability increases through 2000 depends on what Government action is taken.

--Broad Federal Government action may be required in all phases of the coal fuel cycle if coal is to make a significant dent in the oil and gas supply problem.

--The more successful the Government is in pushing the coal solution, the greater will be the public health and environmental costs. Given the current state of coal extraction and combustion technology, the Government will be able to moderate these costs to a certain extent but not eliminate them. Therefore, these public health and environmental costs are tradeoffs in exchange for reduced dependence on foreign energy sources, a political and economic necessity.

--Rapid coal development will leave the Federal Government with difficult problems. When do the costs of the coal solution become unacceptable, or when do the coal costs exceed the considerable benefits of reduced dependence on foreign energy sources? It is not a problem which can be answered by comparing one set of numbers labeled "costs" and another set labeled "benefits." The full costs of increasing coal use can never be completely quantified nor can the benefits of decreased dependence on foreign energy sources. It is, ultimately, a matter of value judgment, and the only way of resolving it in our system is through the democratic process. If it is decided that the costs of coal use beyond a certain level are too much and that increased oil imports is not a tenable alternative, then the Nation, it seems to us, has only two major alternatives open to it between the present and the year 2000.* One, the United States can accelerate the expansion of conventional nuclear power so that nuclear-generated electricity substitutes for oil or gas use wherever possible; and, two, increased energy conservation.

*This assumes that renewable energy sources such as solar energy or the breeder reactor cannot make a significant contribution to the Nation's energy supply until sometime in the next century.

The nuclear option, however, is limited in this period by the time it takes to plan, license, and build new nuclear plants--about ten years--and nuclear power has social costs of its own which must be carefully weighed. Energy conservation is limited too--limited by the time it takes to replace less energy efficient equipment and processes with more efficient technology and by availability of capital. The turnover rate in the Nation's automobile fleet is about 10 years, but the Nation's stock of buildings and industrial capital equipment is replaced over an even longer time.

This, then, leaves only one other major option for the medium term--the next 25 years--and that is reduction in energy consumption beyond what can be achieved through greater efficiencies. But to date, there is no indication that the great majority of Americans are willing to take this course. To be effective, it would require substantial changes in behavior patterns, especially in transportation, in housing, and in the workplace. The tradeoffs in this case could be inconvenience and curtailed growth in income.

SUBSTITUTION

The prospects of substituting coal directly for oil or gas are limited in the industrial sector and almost negligible in the other major sectors of the economy--transportation, commercial, and residential.

A more promising prospect is the substitution for oil and natural gas of coal-generated electricity in the short-term combined with coal-generated synthetic fuels later on. The primary constraints in this case are the time it takes to build new coal-burning electricity generation facilities--five years--and the availability of capital to replace oil- and gas-burning facilities. The advent of synthetic fuels awaits resolution of complex technological and economic problems.

Our study indicates that a most promising short-term opportunity for substituting coal for oil or gas is through improved electricity load management. Oil and gas are used primarily to meet peak load electricity demand while coal (along with nuclear power) is used for baseload. Therefore, leveling the load curve and improving coordination between power systems would increase utilities' consumption of coal and reduce their demand for oil and gas. GAO's calculations indicate that improved load management could increase

utility consumption of coal by 1985 by as much as 149 million tons. This represents a savings of 1.4 million barrels of oil equivalent per day.

In the future, the most significant opportunities for coal substitution for oil and gas are through coal gasification and liquefaction. But, according to the Energy Research and Development Administration's "best estimates," coal gas prices in the year 2000 will be 24 percent higher than projected natural gas prices and coal liquid prices will be 66 percent higher than projected oil prices. Thus, if coal liquids or gas are to make a significant contribution to the Nation's oil and gas supplies sometime before the year 2000, massive Federal subsidies may be required to overcome their economic disadvantage. In addition, it appears that the coal gasification and liquefaction processes will also create air and water pollution hazards. Methods to mitigate these hazards are being researched.

SUPPLY CONSTRAINTS

For purposes of analysis, GAO used the Bureau of Mines and Edison Electric Institute scenarios. Both projected significant growth in coal production--to 779 or 988 million tons by 1985. Coal production in 1976 in the United States was 665 million tons. These increases would require an annual growth in coal production of from 1.8 percent to 4.5 percent, compared with the annual growth rate during 1950-1976 of less than 1 percent. (President Carter's National Energy Plan calls for an increase in coal production of even greater dimensions--to 1.2 billion tons by 1985.)

By the year 2000, the scenarios project coal production of 942 million to 1.6 billion tons. According to GAO calculations, an expansion of coal production of this magnitude would require:

- Opening 438 to 825 new mines.
- Recruiting and training 288,300 to 531,000 new miners (current average employment--208,000).
- Manufacturing significant quantities of mining equipment (draglines, etc.,).

--Capital investments (just for extraction)
of \$26.7 to \$45.5 billion.

The coal industry and the coal-equipment manufacturers may be hardpressed to meet these requirements. However, GAO's discussions with 11 major coal producers (including 9 of the top 15 producers in 1975) showed that all believed the industry could double production by 1985 and triple production by 2000 under existing conditions. Whether the increased level suggested in the National Energy Plan can, in fact, be achieved depends upon several interrelated but difficult to predict factors:

--Coal mining productivity, i.e., tons produced per worker day--it has been declining since 1969.

--Good labor-management relations.

--Worker availability and training, including mining engineers.

--Improved mining technology.

Of all these factors, labor-management relations could perhaps have the most impact. In years when a national agreement is renegotiated, the lost working time due to work stoppages is considerable--for example, eight percent of the total work time was lost in 1974. The current agreement of the United Mine Workers and the Bituminous Coal Operators Association, Western Surface Miners, and National Construction Contractors expires December 6, 1977. The right to strike over local grievances is a major point of contention at the present between the union and the industry.

The regional impacts of increased coal production will be quite varied. While increased coal output may be difficult from a production standpoint, it will also place added demand on the transportation system.

Railroads will be the principal mover of coal in the foreseeable future. Railroads carried about 65 percent of the coal traffic in 1975. The waterway system, although the cheapest way of transporting coal, does not directly serve many of the areas scheduled for major coal development and is limited physically by ice in the winter and by the capacity of its locks. Trucks and high-voltage power lines cannot compete in terms of price. For example, a recent BOM study of western coal alternatives found that mine-mouth generation

and shipment of electricity by extra-high voltage transmission lines was about 30 percent more costly than railroads. That leaves slurry pipelines, and they appear to be competitive in terms of price with railroads. However, slurry pipeline development is being hindered by difficulties in assembling rights-of-way, by water shortages at point of origin, especially in the West, and by environmental problems caused when the effluent from the pipeline is disposed of at the destination.

By 1980, the Nation's railroads anticipate a 95 percent increase over 1974 coal traffic. The most dramatic increase will occur in the West. The entire upsurge in coal volume will require large investments in hopper cars, locomotives, and improved facilities, especially track beds.

GAO's discussions with selected western carriers and with the Federal Railroad Administration indicate that the western railroads will be able to expand their coal handling capacity. An important element in this conclusion is the fact that less time is required to expand rail facilities than to construct new mines or electric generation plants. Even so, the railroads will have to raise considerable capital in order to be able to deliver the future volume of coal. Among the factors that inhibit their capital formation is the Interstate Commerce Commission's restrictions on long-term coal contracts. Railroads point out that they are the only major participants in the coal fuel cycle who do not operate on the basis of long-term coal contracts.

In addition, increased coal production will require expanded coal transport capacity in the Northeastern and Midwestern areas now served by Conrail, the federally-subsidized consolidation of the insolvent eastern and midwestern railroads. Therefore, it will be the Federal Government's responsibility to see that adequate funds are allocated to increase coal handling capacity during Conrail's costly rehabilitation.

ABATEMENT COSTS

The most crucial factor facing the goal to increase coal use is the environmental issue. With the passage of the recent surface mining legislation, only time will tell if sufficient coal will be able to be mined. It appears to us that the National Energy Plan's goal of 1.2 billion tons by 1985 likely will not be met. The air quality restrictions will be the primary deterrent. Utilities and other coal burning industries have been reluctant to make the investment decision to install scrubbers, having been uncertain about the final air quality standards and what will constitute "best available control technology." These utilities and industries

in turn are therefore naturally reluctant about awarding long-term contracts to coal producers. The coal producers, under these conditions, naturally hesitate to conclude the necessary expansion plans and order the needed equipment.

Controlling the air pollutants emitted by coal-burning powerplants, as required by the Clean Air Act of 1970, as amended, will be costly. GAO estimates cumulative capital costs of about \$19.1 billion by 1985 and \$26.4 billion by the year 2000. These costs will vary among regions. But the average residential consumer's electric bill could increase four mills per kilowatt--an increase of about nine percent by 1985--to cover the cost of sulfur oxides and particulate pollution abatement.

GAO further estimates that the cost of coal mine reclamation, subsidence prevention, and acid mine drainage control would cost about \$1.2 billion by 1985 under the BOM scenario.

Moreover, the disposal of the sludge which collects in such air pollution control devices as scrubbers also will be very costly. To put this problem in perspective, the amount of solid waste generated annually under the BOM scenario by 1985 by air pollution control devices will be roughly the same as the total municipal solid waste produced in the United States during the course of a year.

Increased coal production will also mean a population influx into coal producing areas. To meet the needs of the increased population, local communities will have to expand such public facilities as schools, roads, hospitals and health clinics, and sewage systems. GAO estimates that these infrastructure costs to local governments might run as high as \$4.4 billion between 1974 and 1985 and \$14.9 billion between 1974 and 2000. Some States, such as Wyoming, have taken steps to help local communities deal with these costs. The Federal Government has also provided limited assistance through various programs. Regardless of whether Federal assistance is expanded, the effectiveness and efficiency of the Federal aid to affected communities would be enhanced if one Federal agency was made responsible to coordinate the Federal effort.

TRADEOFFS

Human health

Coal combustion emits a number of potentially dangerous pollutants into the air. Some of these, such as sulfur oxides, are regulated. However, for other pollutants from coal the current state of knowledge and technology is such that regulation is not possible. Hence, increased public health and environmental damage are tradeoffs for increased coal production and use.

Small particulate pollution--The current particulate control devices fail to capture many of the particulates one micron or smaller in size which are emitted during coal combustion. These small particulates are thought to pose a special public health hazard because they penetrate the respiratory system's natural filters and lodge deep within the lungs. These could represent the major vehicle by which chemicals such as sulfur oxides cause illness and premature death.

Trace element pollution--Coal pollution also contains quantities of mercury, lead, beryllium, arsenic, fluorine, cadmium, and selenium. Data about them are limited but enough is known to suggest that they could cause serious consequences.

Coal mine health and safety--Coal mining also causes premature deaths, disabling injuries, and illness (black lung disease) among miners. Since the passage of the Federal Coal Mine Health and Safety Act in 1969, some progress has been made in making mines safer places to work, but many problems remain. Coal mining is still the most dangerous occupation of its kind in the Nation. For example, the fatality rate among underground and surface miners was .41 per million worker-hours in 1975, compared with .03 in manufacturing overall. If the current fatality and disability rates do not change, GAO estimates that some 4,700 coal miners might be killed and 351,000 disabled under the BOM scenario through the year 2000. This, too, is a tradeoff for more coal.

Global climate change

Carbon dioxide emissions from coal combustion are not considered directly harmful to human health but their accumulation in the atmosphere could trigger climatic changes with potentially serious consequences.

There is no question that carbon dioxide build-up in the atmosphere has increased in this century and that coal combustion has contributed greatly to the build-up. Many believe this build-up could cause a global warming trend, but they do not know how or of what magnitude. The hypothesis is that carbon dioxide in the atmosphere allows solar radiation to reach the earth but, acting somewhat like a greenhouse, does not allow as much heat to escape as normally would. Knowledge of the phenomenon is sufficient to arouse concern but not adequate to provide a basis for meaningful action.

Some have warned that after the carbon dioxide accumulation in the atmosphere reaches a certain, undetermined point, it may set in motion changes in global weather patterns. An annual global climate change of only 1 to 2 degrees centigrade could have implications affecting global air movement patterns, and redistributing temperature patterns and precipitation levels.

Because of the very limited data, this is a risk which is uncommonly difficult to assess.

Diminished agriculture output

The sulfur oxides pollution from powerplants, even those with controls, causes some crop and plant damage. Coal mining, particularly surface mining, will also reduce agricultural and forest production by the sheer disruption of land--at least during the life of the mine and perhaps afterward. The productivity of some surface-mined land can be restored if care is taken to replace the overburden, especially the topsoil, after mining. This assumes, however, that the area receives adequate rainfall (more than 10 inches on average) and is not too steep a slope (20 degrees or less). But it has yet to be demonstrated whether the croplands of the Midwest can regain their former level of productivity after surface mining. This is another tradeoff for more coal.

Under the BOM scenario, over 99,000 acres of land will be disrupted annually by surface mining from the present through 1985; more than 159,000 acres will be disturbed by the year 2000. By 1985, we would be digging up an area twice the the size of the District of Columbia.

Water quality and supply

Another tradeoff of increased coal producing is reduced water quality in the Eastern United States; in the West the tradeoff is less water availability for municipal and industrial use, agriculture, and recreation.

Drainage from coal mines has polluted over 6,700 miles of this Nation's streams with a mixture of sulfuric acid, iron, and aluminium salts--a compound sufficiently potent to kill aquatic life. Over 90 percent of these streams are in Appalachia. It is not certain how much of this drainage can be controlled and more acid mine drainage may be a tradeoff of increased coal production.

In the West, coal development makes the already scarce water resources even scarcer. In particular surface mining is known to lower ground-water tables and disrupt underground aquifers. And coal-related developments such as coal-burning powerplants and coal gasification and liquefaction facilities are big water users. In relatively large areas of the West, water supplies are already overbooked through interstate, international, and Indian agreements; ground-water tables are steadily dropping in some areas as more is consumed each year than nature can replenish. The increased demand of coal development will certainly cause legal as well as environmental difficulties relating to water in the West and will divert water from other uses.

Social change

Even if communities affected by coal development manage to obtain adequate initial financing to meet their increased public service needs, social patterns will change with the population influx. Obviously, the extent of the change will vary greatly from community to community, but in general, communities in the more sparsely populated West will feel the impact more than those in the East. Their way of life will change. This is a tradeoff. Once quiet and highly personal in character, these communities will become more crowded, faster-paced, more impersonal. Examples of the phenomenon, which are described in this study, are Rock Springs and Green River in Sweetwater County, Wyoming, but there will be others as coal development increases. Through adequate planning and financing, the impact can be cushioned, but it will be an impact nonetheless, and the social fabric of the community will change.

SPECIAL CONCERNS FOR POLICYMAKERS

If, despite the tradeoffs, it is decided to try to double coal use by 1985 and to triple it by the year 2000, policymakers will be faced with a set of special, coal-related concerns.

One is that the current data concerning coal resources and reserves are extremely spotty and outdated. Why is this a concern when coal resources and reserves are so large?

First, because coal is a finite resource and will not last forever. Current coal reserves, for instance, will last only 74 years under an annual demand growth rate of 3.69 percent. Furthermore, certain coal with highly desirable qualities is much more limited in supply, and to make decisions affecting their use, more accurate estimates of their reserves are necessary. For example, reserve figures for metallurgical coal, which is essential in the manufacture of steel, could affect Government decisions regarding its export. Or reserve figures for low-sulfur coal could affect the air pollution regulations and the Federal Government's leasing of its vast coal resources in the West. The Federal Government owns about 70 percent of the coal in the West and can influence the development of another 20 percent bordering Federal lands.

The alternatives that may be considered for improving the reliability and usefulness of coal data include increased Federal exploration--stratigraphic drilling and mapping--as well as providing coal companies with special tax and other incentives to submit reserve estimates to the Government that are accurate and conform to certain criteria, such as the sulfur content and metallurgical qualities of the coal, if any.

Coal reserve figures now received from coal companies and other proprietary sources are possibly understated in an effort to minimize property taxes. The exact magnitude of the underestimation is not known.

Recent surface mine legislation restricts surface mining in alluvial valley floors, because they are important to water systems and agriculture, and on steep slopes. The amounts of coal reserves affected in the first instance are small; in the second they are unknown. The legislation also seeks to protect surface owner rights on Federal coal lands. One study indicates that as much as 14 billion tons of coal could be withdrawn from potential production under such measures, although this estimate is highly uncertain because more reliable and accurate reserve data on Federal coal land are needed.

A second coal-related concern for policymakers is the matter of how to handle external costs. In principle, the external costs of producing and burning coal should be internalized into the price of coal whenever possible. In this way, the users of the coal, or of the electricity generated by coal, will be paying the true cost of the product and may have a greater incentive to use it efficiently. In practice, this is difficult to do. For

one reason, how do you include the cost of a human life when coal pollution causes a premature death? In addition, the more that external costs are internalized, the higher will be the price of coal or electricity, and the more attractive will become oil and gas. Thus, the goal of reducing dependence upon foreign energy sources will have been thwarted to a certain extent.

For example, in an effort to raise revenue to meet the socioeconomic and environmental costs of coal development, Montana now imposes a 30 percent tax on coal (market value) that is surface-mined. This is, in other words, an effort to internalize these external costs. However, by so doing, Montana inhibits the achievement of two national goals--clean air, because a significant amount of the Nation's low-sulfur coal is found in Montana, and reduced dependence upon oil imports and dwindling natural gas reserves. For another example, New Mexico now taxes electricity produced within the State and then rebates the amount of the tax to citizens of the State. This is, in effect, an energy export tax --raising the price of electricity, which is primarily coal generated, to consumers in Arizona and California.

The utility industry relies far more heavily on Government-financed research and development than do many other industries. In a sense, this is a form of subsidy to electricity users because otherwise they would have to bear a greater share of research and development costs. One solution would be to place a Federal tax on electricity that is earmarked exclusively for research and development in technologies for electricity generation which are clean and do not rely on oil or natural gas. However, such a tax might discourage the substitution of electricity for oil and natural gas because of the added expense.

Another area of concern for policymakers is coal prices. The concern here is that coal producers do not reap windfall profits from Government-induced market trends. For example, if the Government prohibited the further use of oil or natural gas by utilities, coal producers might be in such a position.

When coal prices more than doubled in 1974, the Council on Wage and Price Stability concluded: "Unless all other costs have grown more quickly than labor costs (which appears doubtful), the average price has also outpaced total costs." Their study of selected coal companies in 1974 found that net coal profits rose to \$2.80 per ton, or 18 percent of the average value per ton.

In this context, it should be noted that the structure of the coal industry has undergone a radical transformation in the past 15 years. The number of independent firms in the coal business is declining sharply and ownership patterns are changing. As of 1974, 31 firms accounted for approximately 58 percent of total coal output. At present, of the 20 biggest holders of domestic coal reserves, only two are independent coal companies. Eleven are oil companies. There is little evidence, to date, however, that the increasing concentration of power within the coal industry has made for an uncompetitive market. One effect of large oil, chemical, and other non-coal companies buying up smaller coal independents has been to greatly increase the capital available to the industry for expansion.

A final area of special concern for policymakers is coal exports. Traditionally, the United States exports 9 to 11 percent of its annual bituminous coal production. In 1975 coal exports contributed \$3.3 billion to the Nation's balance of payments. This must be kept in mind if policymakers are considering export curbs, for instance, in the case of a temporary coal shortage.

About 77 percent of U.S. coal exports was metallurgical coal for foreign steel manufacturers. Although stiffer competition from other coal exporting nations is expected in the future, U.S. metallurgical coal exports are projected to grow at an annual rate of 1.71 percent, according to BOM. U.S. steam coal is less competitive and exports are expected to increase only slightly.

NECESSARY FEDERAL ACTIONS

If the coal solution is to work--that is, help reduce dependence on oil imports and relieve pressure on dwindling domestic natural gas reserves--then certain Federal Government interventions in the coal market place will be necessary at key points.

The administration has already proposed in the National Energy Plan a number of Federal actions to increase the use of coal. These include

- a regulatory program to require coal use by utilities and large industries, with allowances for exceptions;
- an oil- and gas users tax and rebate/investment tax credit system to provide an economic stimulus to convert to coal;

- an environmental policy for coal which the administration hopes will achieve its energy goals without endangering the public health or degrading the environment; and
- a research program for coal conversion, mining, and pollution control technology.

In GAO's An Evaluation of the National Energy Plan, we assessed the specific administration proposals and pointed out that while the administration's plan deals with some of the constraints to increased coal use, it does not deal with transportation, productivity, and other constraints that will hinder the achievement of one billion tons of coal production and use in 1985. Based on the work then underway in preparing this particular report, we also noted the need for

- capital to upgrade large portions of the Nation's railroads, particularly in the Eastern States, together with the need to expand existing capabilities;
- congressional resolution of uncertainty concerning the issue of rights-of-way for slurry pipelines;
- improved labor relations to prevent disruptions due to wildcat strikes, together with the need for improved miner health and safety conditions, recruitment, and training;
- greater productivity;
- accelerated Federal research to determine the health and environmental effects of burning greater amounts of coal; and
- less costly and more reliable technology to control air pollution from coal burning facilities.

A FINAL NOTE

As we have seen, the short run capacity (a year or so) of the coal industry is limited to what can be extracted through increased production at existing mines (surge capacity).

Many interrelated elements would have to work if coal production and use were to double by 1985: mining equipment manufacturers would have to fill orders promptly and mining companies must have the foresight and capital to be able to open new mines when the added output is needed, to name only two. The time required to open a new mine varies: surface

mines in the East take 1.5 to 3 years to open; in the West they take longer--3 to 13.5 years; underground mines in the East take 4 to 15 years to open and 2 to 5 years in the West. In the short-term coal is also constrained on the consumption end, in the sense that utility and industrial users are not going to buy coal if they do not have the physical capacity to use it. There are long leadtimes involved just in building and installing boilers at existing plants, not to mention the leadtimes involved in planning and building completely new coal burning plants. It is impossible to predict whether the coal fuel cycle can, in fact, be pushed to the extent of doubling production and use by 1985. The uncertainties are many, but sufficient to raise serious doubts.

In the medium term (1985-2000), coal is demand-constrained. The possibilities of direct substitution for oil or gas are very limited on an economy-wide basis. The prospect for indirect substitution by coal-generated electricity, while more promising, is limited too by economics and the current state of industrial and transportation technology. Over a longer term, coal seems to be both supply-constrained, especially in terms of low-sulfur coal, and demand-constrained. The long-term prospects for increased coal demand ride upon the hope of coal gas and liquids becoming environmentally-safe and economical energy fuels.

These, then, are the physical and economic limits of the coal solution.

If maximum coal output and consumption can be achieved within these limitations, the tradeoffs may be costly, particularly in terms of human life and disease. These tradeoffs can only be considered tolerable when viewed in the broader context of the Nation's inadequate oil and gas resources as well as the risks and limits of nuclear power. The coal tradeoffs are sufficiently significant to put renewed emphasis on the need for vigorous energy conservation, not as an alternative to coal, but to temper somewhat coal's very high costs.

Because of the long leadtimes to translate Government policy and action into actual coal production and consumption, we believe it is more realistic to assume that while Government policies set in motion now will have some effect between now and 1985, the greater impact will be in the 1985-2000 period.

In our report to the Congress, An Evaluation of the National Energy Plan, we assessed the various recommendations of the administration to increase coal use and concluded that

a lot more needed to be done. We also noted that the work we have been doing in GAO on the production and use of coal raises doubts about the possibility of achieving the administration's plan of producing and using 1.2 billion tons of coal by 1985. Given all the physical, economic, environmental, and public health considerations, it appears to us that producing and using even a billion tons by 1985 would be difficult. Assuming, however, that the difference between the administration's plan and reality is a matter of 200 million tons, we calculated that this would be a shortfall on the domestic energy supply side equivalent to an annual use of 2.3 million barrels of imported oil per day, as presented in the fuel balance tables in the National Energy Plan. Our calculation was based on the administration's estimates of what a shortfall of 200 million tons of coal would entail. However, the administration used an average Btu rate conversion factor which does not reflect the true value of the oil equivalent of coal.

Using appropriate conversion factors for each use where coal would substitute for oil, we estimate that the 2.3 million barrels of oil shortfall noted above would actually be 2.2 million barrels of oil equivalent per day.

Upon further review, we have discovered another problem. As noted above, the administration calculated supply and demand on the basis of quadrillion Btus and then converted these to millions of barrels of oil a day equivalent. Using the same conversion factor analysis as above, we estimate that the oil equivalency of the remaining one billion tons of coal could be 1.1 million barrels per day less than the administration's figures shown in the fuel balance tables in the National Energy Plan. Thus the number of barrels of oil equivalent per day shown in the fuel balance tables for one billion tons of coal (without the energy plan) should be 11.1 million barrels per day instead of the 12.2 million barrels shown.*

The GAO and administration estimates of quadrillion Btus are identical. The difference of 1.1 million barrels of oil per day equivalent results from the different conversion factors used. If this difference implied a real world shortfall, it would have to be made up in one of three ways: additional imports; increased domestic production from other sources; or increased conservation efforts. If, on the other

*These figures should be adjusted downward by 1.4 million barrels per day equivalency for metallurgical coal which has no oil substitutability.

hand, the oil equivalent numbers in the National Energy Plan simply reflect a mechanical use of an average conversion factor from detailed estimates based on actual quantities, there would be no shortfall since both supply and demand would be less in barrels of oil equivalent. As discussed in the next paragraph, we are continuing our investigation into this possibility.

In any case, these considerations raise questions about the factor used by the administration in converting to barrels of oil equivalent per day for other domestic energy sources, which in turn raises questions about the administration's total estimates regarding energy supply and demand. We believe the administration should either have presented its analysis on the basis of Btus or used a more detailed set of conversions to oil equivalency which recognized historical and other trend data in developing the conversion factor. Otherwise, we believe that the net effect could be to increase the total energy supply and demand estimates when stated in barrels of oil equivalent. While not part of this study, we are continuing this analysis and will be reporting our findings to the Congress.

With all the constraints, however, the increase in use of coal in absolute terms will still be substantial. Electric utility plans through 1985 call for an increase of over 300 million tons. Industrial use will increase also, but more slowly. There is no question that coal will supply a part, a large part, of the Nation's energy future. So will foreign oil and nuclear power. Natural gas will decline and may have to be restricted to optimum end uses such as home heating, etc.; domestic oil will decline. Solar energy will increase slowly, as a complement to other fuel types. On the demand side, the best answer to the Nation's energy bind is conservation, through increased efficiency and decreased use.

AGENCY COMMENTS AND OUR EVALUATION

Numerous Federal agencies provided comments on a draft of this report, as did private industry organizations and technical consultants. We took those comments into consideration in preparing the final report.

We also provided a copy of the final draft report to the Energy Policy and Planning Staff in the Executive Office of the President. The Staff's comments are included at page VIII.1.

The Staff states that its only major area of disagreement is with our conclusion that "no more than one billion tons of coal could be produced between now and 1985." The Staff then discusses several points regarding this conclusion.

The staff identifies three basic areas of disagreement:

--Recent surface mining legislation.

--Railroad expansion problems.

--Air quality regulations.

We support the surface mining legislation as an essential tool for protecting the environment, but recognize that it will be a constraint to coal development, although the impact of that legislation from a coal development standpoint has not been fully evaluated.

Railroad expansion problems are a major constraint, in our view, along with the substantial expansion difficulties that will face coal producers and coal users who will be dealing with heavy capital and operating costs and long lead time problems for mine opening, land reclamation, boiler installation, air pollution control, and scrubber sludge disposal.

The Staff's comments regarding air quality regulations are not very clear. For example, the Staff says that the requirement that coal-burning plants make use of best available control technology (BACT) would not be in effect until 1982, and thus would have minimal impact by 1985. The very point we are making is that the uncertainty over those requirements is causing problems (see pp. 6.50, 6.51, 9.6, and 9.7). In any case, the impact on coal production and use (particularly of higher sulfur coal) is bound to be substantial because both consumers and producers must take BACT into account in their long-range planning.

As far as the regulations regarding prevention of significant deterioration and EPA's offset policy for non-attainment areas are concerned, the Energy Policy Staff raises the question of whether these are substantial constraints or deterrents to coal development. Whether the air regulation constraints will be substantial, when taken individually, is a matter of judgement, but when considered collectively we are persuaded by the weight of the evidence we have reviewed that the coal fuel cycle--production, transportation,

and use--will not expand as fast as the administration anticipates. We want to affirm, however, that we do support the air quality regulations as necessary environmental protections.

The Energy Staff also states that GAO has not addressed how much of an increase in coal production can be achieved due to the initiatives in the National Energy Plan. We believe we have argued that point to a reasonable conclusion, both in our earlier report, An Evaluation of the National Energy Plan, and in this report. Using the administration's own figures, the National Energy Plan would increase utility use of coal only a few million tons per year. The balance of the 200 million tons per year projected impact of the National Energy Plan is anticipated in the industrial sector. We believe this is extremely unlikely to occur in the 1985 time-frame because of the myriad of constraints to rapid development of the coal fuel cycle we have documented in detail in this report.

The Staff fails to address other, very important issues that we raise--issues that we see as major constraints to achieving annual coal production and use of one billion tons by 1985. Those issues are identified, with appropriate page references, in the Digest to this report.

TECHNICAL APPENDIX ON MODELS

During the course of this review, we analyzed all of the major energy models* which might have provided us with additional insight into the problems of coal development. We were, however, unable to use these models because they did not accord requisite attention to coal and were not fully developed and operational. The following is a discussion of our analysis of the major energy models--Federal Energy Administration's National Coal Model (NCM); Data Resources, Inc. (DRI) energy model; Wharton Econometric Forecasting Associates, Inc. Coal Satellite Model; Chase Econometric Associates, Inc. energy model; and Stanford Research Institute (SRI) energy model.

A new coal model available in 1977 is FEA's NCM and related support models. We believe this model will be a significant contribution to coal analysis for several reasons. It is large enough in size to deal with major economic variables on a national as well as a State level. While specializing in coal, it also considers the economic trade-offs to other energy resources. NCM relies upon the FEA Project Independence Evaluation System (PIES) model and a related econometric model to determine consumer demand for coal and energy related products. In the course of this brief description, we merely refer to this group of models as one, namely, NCM.

NCM is new and, therefore, we were unable to judge its predictive accuracy. Its structure is unique enough, however, to warrant some description. Most energy models are of an econometric variety. Specifically, they rely upon the historical relationships of certain factors and the assumption that those relationships will persist in the future. An example of one such relationship would

*The term model, as used here, means the mathematical representation of things as they are. Energy models deal with energy and energy related variables, whereas macro-models deal with a wide range of general economic variables such as interest rates, fixed investment, disposable income, gross national product, and economic growth. The term econometric is used to describe the statistical technique used to test the form and strength of historical relationships among economic variables.

be the growth in energy demand relative to the gross national product. NCM, on the other hand, is a linear programming model relying principally upon current relationships. Since there is no historical (time series) data in NCM, it is said to have no "memory." Accurate information on current data and relationships is essential because NCM cannot rely upon historical data to temper its forecasts. A linear programming model such as the NCM typically asks the question: What is the most (or least) coal that will be produced given such constraints as known reserves, anticipated demand, substitute products, market prices, transportation costs, etc.?

The strengths of NCM are in its ability to deal with such a wide variety of coal related variables (such as production and transportation costs, types of coal, and geography) and its handling of the supply sector. Its shortcomings are principally due to the fact that it is not completely developed yet and that it must deal with known resources (having no ability to deal with undiscovered resources on the level of detail required). It is not now, nor is it expected to be, available to all potential users in the future. Due to the nature of its constraint equations, it has to assume some seemingly unrealistic assumptions such as perfect knowledge in the market place,* and the unchanging nature of price relationships.

The major alternatives to NCM are the econometric models designed by private organizations such as DRI, Wharton Econometric Forecasting Associates, Inc., Chase Econometric Associates, Inc., and SRI. The DRI model is the simplest to use and was available in 1975; the others will be available in 1977 or later.

A thorough study of these models would consider predictive accuracy, basic structure, and other such characteristics. This review does not attempt such a study. However, we have examined each of the major models to ascertain its principal strengths and weaknesses.

*Producers and consumers do not have perfect knowledge. They do not know each others costs, profits, and other economic constraints. This imperfect knowledge precludes a producer or consumer from making the best decision in each situation.

The DRI energy model has been available for some time and, consequently, considerable effort has been made to refine it. The Chase model expects to have greater detail on a geographic basis. Both of these models deal with all energy and rely upon links with their respective macro-models of the entire United States to develop a complete economic picture. Wharton also relies upon its macro-model for support; however, it differs from the other two in two respects. First, it is a coal model--not a general energy model--and addresses coal problems more specifically. Second, considerable effort was expended to develop the supply side of the model, a weakness of most other econometric models. Nonetheless, it does not handle the broad range of detail on the supply side that the NCM does. SRI also has an energy model somewhat similar in nature to the other econometric models. Due to its extended forecast horizon (year 2025), it is of necessity more general. It essentially establishes a series of supply and demand equations which it solves simultaneously given the forecast assumptions, and other exogenously determined variables. It is not publicly available through timesharing as the other econometric models are and it requires additional development to handle the same types of problems the other econometric models do.

While the four econometric models differ considerably, they can be grouped and compared, as an econometric composite, to NCM. Of course, such a comparison is necessarily a rough approximation.

Our study of these models was not intended to determine the best model. Each model has an intended purpose not necessarily related to the particular purpose of another model. Best, therefore, can only be determined in relationship to a specific question or analytical requirement. We have attempted here to highlight some of the strengths and weaknesses of each model insofar as information was available to us.

A summary of the relative strengths and weaknesses of NCM and the econometric models is shown in table 1.

Earlier portions of this report have shown that coal development is limited by demand. We found that forecasting demand in detail was difficult after about 1985. This makes most models imprecise for addressing the basic question: To what extent can coal substitute for other fuels, especially after 1985?

Much has been said of the modeling capability available today, and we are convinced that some of these models will be able to make substantial contributions to analysis of the coal market in the future.

Econometric models currently tend to break down in predictive accuracy as the period of forecast is extended. This deficiency is usually finessed by aggregation, i.e., the detail is eliminated and only major variables on a national level are forecast. This type of forecast was insufficient for our review.

Linear programming models have no memory; working only with cross sectional data they are only as useful as the analyst is skillful in his estimation of future demand. NCM, unfortunately, is still in a developmental stage, and, therefore, was not used extensively in this review. We expect that NCM will be very useful in the comparison of various scenarios when it is complete.

For the above reasons, the present study makes very limited use of NCM or econometric models.

Table 1

Major Advantages and Disadvantages of National Coal Model and Econometric Models

<u>National Coal Model</u> (FEA)		<u>Econometric Models</u> (DRI, Wharton, Chase, SRI)	
<u>Pros</u>	<u>Cons</u>	<u>Pros</u>	<u>Cons</u>
Rich in detail	Unrealistic assumptions about behavior, e.g., pure competition, absence of risk, etc.	Realistic assumptions about behavior	Lack of detail
Thorough analysis of supply		Strong analysis of demand	Insufficient specificity of supply
Excellent treatment of current institutions	No allowances for changes in existing relationships		Inadequate recognition of present differences in coal qualities, prices, and regions
No time constraints on period of forecast; detail is not sacrificed as forecast horizon is extended		Strong on short run forecasts; however, necessitates generalities as forecast horizon is extended	
		Publicly available through timesharing	

A FURTHER LOOK AT COAL CONSUMPTIONIN 1985 AND 2000

In chapter 2 we summarized coal demand in 1985 and 2000 under two alternative scenarios. This appendix will delineate and discuss the implications of these two scenarios in greater detail.

The decomposition of gross energy demand by major consuming sector and by principal fuel category is contained in table 1. This is rather complex material, some of which has already been discussed.

Table 1 illustrates that the contribution of natural gas under the Edison Electric Institute scenario declines markedly during 1985-2000 from about 28 to 18 quadrillion Btus. A smaller decline in oil consumption also occurs.

The oil and gas decreases under the EEI scenario are more than offset by the development of synthetic gas from coal and the growth of nuclear power. Note that the decline in oil consumption is almost entirely absorbed by the transportation sector, which shrinks during 1985-2000. Shrinkage for oil and gas also occurs in the direct energy input to the household/commercial and industrial sectors. Unlike transportation, however, these other sectors can use the output of the electrical sector to a significant extent.

Under the high demand (Bureau of Mines) scenario in table 1, usage of oil increases some 22 percent during 1985-2000. The BOM scenario also shows that oil usage by utilities declines during this period, while under the EEI scenario, utility oil usage remains constant. In effect, the EEI scenario assumes that increasingly scarce oil supplies during 1985-2000 would not be "bid away" from, or re-allocated from, the electrical sector to the transport sector. Such an assumption appears implausible.

The BOM scenario also projected some unlikely occurrences. Synthetics from oil are projected to increase six-fold during 1985-2000, despite the limited commercial development thus far. Similarly, the growth rate for total energy under the BOM scenario is 3.4 percent per year for 1975-2000. In contrast, equivalent growth rates for selected periods in the past were as follows.

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<u>Period</u>	<u>Annual growth rate in energy demand</u>
1925-50	1.97
1925-75	2.48
1950-75	2.99
1965-75	2.91

The EEI scenario, taken by itself, predicted utility coal consumption to be 437 million tons by 1985. This level was apparently attained in 1976. In summary, the assumptions incorporated in the two scenarios appear pessimistic regarding the future coal, but optimistic regarding the level of gross energy demand in 1985 and the contribution of synthetic fuels and nuclear power during 1986-2000.

Table 1

Projected Consumption of Energy
by Major Consuming Sector and by Major Fuels
Under Alternative Scenarios, 1985 and 2000

<u>Consuming sector</u>	<u>Coal</u>	<u>Oil</u>	<u>Gas</u>	<u>Nuclear hydro geothermal</u>	<u>Total gross inputs (note a)</u>
-----quadrillion Btus-----					
<u>1985</u>					
<u>High demand (BOM)</u>					
House/comm.	0.1	7.9	8.5	-	16.5
Industrial	4.9	8.4	9.5	-	22.8
Transportation	-	23.0	0.6	-	23.6
Electrical	15.7	6.2	1.5	15.7	39.1
Synthetics	0.5	1.0	-	-	1.5
Total (note a)	<u>21.3</u>	<u>46.5</u>	<u>20.1</u>	<u>15.7</u>	<u>103.5</u>
<u>Low demand (EEI)</u>					
House/comm.	0.2	8.9	7.5	-	16.6
Industrial	3.4	8.3	14.1	-	25.9
Transportation	-	23.0	1.0	-	23.7
Electrical	11.6	2.8	5.0	14.2	33.6
Synthetics	1.1	0.1	-	-	1.2
Total (note a)	<u>16.3</u>	<u>43.2</u>	<u>27.6</u>	<u>14.2</u>	<u>101.2</u>
<u>2000</u>					
<u>High demand (BOM)</u>					
House/comm.	-	8.0	9.0	-	17.0
Industrial	5.9	10.4	9.0	-	25.3
Transportation	-	28.2	0.6	-	28.8
Electrical	20.7	4.7	1.0	52.2	78.6
Synthetics	8.1	5.7	-	-	13.9
Total (note a)	<u>34.8</u>	<u>56.9</u>	<u>19.6</u>	<u>52.2</u>	<u>163.4</u>
<u>Low demand (EEI)</u>					
House/comm.	0.1	8.2	3.0	-	11.3
Industrial	3.3	8.5	9.7	-	21.5
Transportation	-	19.6	0.6	-	20.2
Electrical	11.1	2.8	4.6	32.5	51.0
Synthetics	5.0	0.4	-	-	5.4
Total (note a)	<u>19.5</u>	<u>39.5</u>	<u>17.9</u>	<u>32.5</u>	<u>109.5</u>

a/May not total due to rounding.

CURRENT FEDERAL EFFORTS TOACCELERATE COAL DEVELOPMENT THROUGH RESEARCH

The prospects for coal development depend crucially on our ability to solve the environmental problems resulting from burning coal. In chapter 2, table 11 we noted that manufacture of gas and oil from coal is not likely to be cost-effective in this century. Yet there is a need to develop such new ways to use coal as a supplement to an oil and gas substitution and conservation effort.

This appendix explores the nature and extent of current Federal efforts to promote further coal utilization through research and development.

UTILIZATION AND CONVERSION RESEARCH
DEVELOPMENT AND DEMONSTRATION

The Energy Research and Development Administration has, among other things, responsibility for Federal coal utilization and conversion research activities. ERDA's conversion research programs have primarily been focused on coal gasification* and liquefaction** which will serve as substitutes for domestic and imported petroleum and natural gas. Processes for converting coal to liquids and gases have existed for years and are generally considered less efficient and more costly than "second

*Coal gasification is the process of converting coal to synthetic gas. To accomplish this, coal is fed with steam and air or oxygen, into a high temperature pressurized reactor. The raw gas produced is referred to as low-Btu gas or utility/industry fuel gas. Low-Btu gas has a lower heat content compared to natural gas and cannot be economically transported over long distances by pipeline. The gas is valuable, however, as a fuel supply for electrical power generation plants or industrial processes using gasified furnaces when a coal conversion plant is located in close proximity. Low-Btu gas can be upgraded by a process called methanation to high-Btu gas. High-Btu gas has approximately the same heat content as natural gas and can be substituted in existing pipeline networks to satisfy the demands of natural gas users.

**Coal liquefaction is the process of converting coal into a liquid. One method of accomplishing this is by direct catalytic hydrogenation. In this process pulverized coal is slurried with a coal-derived recycled oil mixed with hydrogen and fed into an ebullated bed with a cobalt-molybdate catalyst producing liquids and gases.

generation" processes currently being developed by ERDA.* These conversion techniques are long range solutions to increasing coal usage and current estimates are that they will not have a significant impact on energy supply until around the year 2000. ERDA is currently predicting that synthetic fuels will supply between .2 and 1.1 quadrillion Btus of energy in 1985; and between 1.9 and 9.5 quadrillion Btus in 2000.** Both projections are small in terms of total demand.

Utilization research is concerned with direct combustion processes. Direct combustion research has been oriented primarily on developing fluidized bed boilers,*** which it is hoped will be a more efficient and more environmentally sound means for burning coal. This process may be ready for commercialization in the mid-1980s.

The objective of ERDA's coal program is to develop the technology needed to make fuels derived from coal available in the form and quantity needed and to insure the development of coal resources on a technically sound, economically feasible, and environmentally acceptable basis. To accomplish these goals, ERDA has divided its program strategy into near-, mid-, and long-term objectives.

Near-term objectives (1975-1985) include the development of improved processes for the direct combustion of coal for electrical power generation and industrial heat, and the conversion of coal to clean liquid and gaseous fuels. Process development includes the construction and operation of demonstration plants which are modules of commercial size plants.

*ERDA's recently published "Fossil Energy Program Report" stated that ERDA is seeking "to determine if any of the processes under development are, in fact, improvements over existing technology."

**Estimates provided by ERDA's Planning, Analysis, and Evaluation Group.

***Fluidized bed combustion involves the burning of coal in a fluidized (suspended) bed of inert ash and either limestone or dolomite. The fluidized state is maintained by the injection of air through the bottom of the bed at controlled rates.

Mid-term objectives (1985-2000) include the development of advanced processes for the combustion of high sulfur coals, the development of advanced electrical power generation systems directly utilizing coals, and the demonstration and transfer of synthetic fuels technology to the private sector.

Long-term objectives (beyond 2000) include the development and demonstration of advanced technologies for producing electric power and process heat at increased efficiency, the development of new synthetic fuels, and the development of underground gasification recovery techniques for coal deposits not recoverable by available technology.

ERDA hopes to increase coal use by developing several parallel and complementary processes rather than selecting only a few processes for intensive development. ERDA argues that the varieties of coal to be processed, coupled with the market requirements for a wide range of fuels, will necessitate the development of several coal conversion and utilization processes. As of February 1976 ERDA had at least 271 fossil energy related contracts outstanding. Some of the processes under development will serve many of the same market requirements.

The development of a process from the initial concept through operation of a demonstration plant normally requires 15 to 20 years.

Table 1

Typical Process Development Sequence
(15 to 20 years)

	<u>1-4 years</u>	<u>4-6 years</u>	<u>5-8 years</u>	<u>8-12 years</u>
Concept	Exploratory research	Process development Unit (PDU)	pilot plant	Demonstration plant
				Commercial plant

The technical capabilities of each process being developed by ERDA are required to be evaluated at each phase to determine the feasibility of carrying the project to the next higher phase. ERDA also performs tentative economic and environmental evaluations beginning with process development units and continuing through pilot and demonstration phases. Sound research and development practices would dictate that inferior processes be identified early in the development cycle

so that research efforts can concentrate on promising processes. In a report prepared for the Office of Management and Budget, ERDA stated that it has been unable to develop reliable techniques for selecting one process, from among competing processes, for further development. ERDA has contracted with Stanford Research Institute to develop a methodology which will aid in selecting on a cost/benefit basis among competing technologies.

ERDA has organized its coal program into nine subprograms. Four subprograms deal with coal conversion, three with the direct use of coal, one with demonstration plants, and another with advanced research and supporting technology.

The cost of developing coal conversion and utilization technology will be high. Funding levels have increased dramatically since the Office of Coal Research began its coal program in 1961. Between fiscal year 1970 and 1974, the Federal Government spent \$277.4 million on coal utilization and conversion research. Between fiscal years 1975 and 1981, ERDA is forecasting it will spend \$4.15 billion. (See chart 1.) This is \$3.51 billion in constant 1975 dollars. This represents a significant increase even discounting the effects of inflation. An additional \$1.7 billion is expected to be spent by industry for cofunding pilot and demonstration plants. ERDA's coal research and development subprograms are discussed on the following pages.

Chart 1

Estimated Expenditures for Coal
Research and Development Between FY 1975 and 1981
by Major Program Expenditures (note a)

-----Billions-----

Direct utilization
(28 percent):

Direct combustion	\$.375
Advance power systems	.307
Magnetohydrodynamics	.497
	<u>\$1.179</u>

Coal conversion
(45 percent):

Liquefaction	\$.926
High-Btu gasification	.399
Low-Btu gasification	.348
In situ	.177
	<u>\$1.850</u>

Other
(27 percent):

Advanced research	\$.367
Demonstration plant	.753
	<u>\$1.120</u>

Total

\$4.149

a/Source for these estimates is ERDA's Fossil Energy
 Five Year Commitment Projections dated February 4, 1976.

Direct combustion

The expanded use of coal in utility and industrial boilers is restricted by national emission standards. Yet, curtailments of natural gas, the high cost of oil, and the uncertainty of foreign oil supplies have created a need for the capability to burn coal cleanly and economically. Current new source performance standards for stationary coal-fired steam generators limit sulfur dioxide emissions to 1.2 pounds per million Btus and nitrogen oxides to 0.7 pounds per million Btus. The high cost of removing sulfur dioxide, through such means as stack gas scrubbing and coal pretreatment, have restricted the expanded use of coal containing high levels of sulfur.

ERDA's direct combustion subprogram is attempting to develop and commercially demonstrate, in the near-term, the direct combustion of high sulfur coal and coal of all ranks in an environmentally acceptable way. The subprogram focuses almost entirely on developing atmospheric and pressurized fluidized bed combustion systems although some effort is being expended on combining coal and oil together as a fuel source, and improving the reliability and efficiency of present boilers. Direct combustion research is only about nine percent of ERDA's fossil energy research budget.

One atmospheric fluidized bed boiler is under construction and one pressurized system is being designed. Technical problems relating to erosion/corrosion rates and the operational stability of large-sized fluidized bed combustion systems remain to be solved before transfer of the technology to the private sector will be considered.

Fluidized bed combustion, under current programs and plans, will be available to industry during the 1980s. In addition, the Environmental Protection Agency, the Bureau of Mines, and ERDA are conducting and sponsoring research on controlling coal combustion stack gas emissions. These research efforts are necessary and vital to any future expanded use of coal.

Synthetic fuels

Liquefaction subprogram

Products derived from coal liquefaction processes could substitute for petroleum refined products in two distinct markets. One market uses boiler fuels suitable

for either electrical power or industrial steam generation. The other market uses quality fuels such as gasoline, methanol, diesel oil, heating oil, and chemical feedstocks.

ERDA supports projects in four liquefaction areas--direct hydrogenation, solvent extraction, pyrolysis, and indirect liquefaction. Most of the projects are currently at the PDU stage of development. H-Coal which is a direct hydrogenation project, is under the pilot plant design phase.

Several technical problems common to most liquefaction processes remain to be solved: (1) solid/liquid separation, (2) durability of equipment such as pumps and valves, (3) a catalyst capable of demonstrating long-term performance, (4) improved reactors for coal and hydrogen contact and (5) upgrading crude liquids to refined products. Several delays have occurred at PDU and pilot plant stages within the last year. ERDA is projecting that liquefaction processes will be available for commercialization after 1990.

High-Btu gasification subprogram

ERDA's high-Btu gasification subprogram seeks to develop second and third generation technologies and improve the economic and technical capabilities of first generation gasification processes.

Improved gasification processes are expected to produce a substitute natural gas capable of augmenting diminishing supplies of natural gas. ERDA is still uncertain, however, if second and third generation processes actually do represent improvements over first generation processes. As in the case with the liquefaction subprogram, ERDA is pursuing several gasification processes that are similar. Each process represents a different approach to high-Btu gasification, but they all have one purpose, the production of substitute natural gas.

The major technical problems commonly encountered when gasifying coal include: (1) clogging equipment, (2) equipment failure under high temperatures and pressures, (3) difficulties in materials handling and gas cleaning, (4) variations in product yields, and (5) inefficiency of the

methanation processes.* ERDA's gasification projects have also suffered delays due to construction problems in the past year, but based on ERDA's demonstration plans high-Btu gasification processes could be ready for initial commercial application after 1985.

Low-Btu gasification subprogram

Low-Btu gasification is a promising method of using coal as a fuel for electric powerplants and industrial processes. Development of low-Btu gasification techniques, although simpler, are not as far advanced as high-Btu techniques. Two projects are at the pilot plant stage of development. Although technical problems are somewhat similar for both low- and high-Btu processes, low-Btu appears to be cheaper and more efficient than high-Btu gasification techniques. ERDA has been criticized for not placing enough emphasis on developing low-Btu gasification techniques. In fact, ERDA estimates that low-Btu gasification processes may be competitive with liquified natural gas (LNG) now. LNG currently sells for about \$3 per thousand cubic feet, and ERDA is estimating low-Btu synthetic gas at \$2.25 to \$2.80 per thousand cubic feet. The \$2.25 would be for an improved second generation process.

In situ gasification subprogram

In situ gasification, the process of burning coal in its natural occurring place and capturing the gases, producing low- and medium-Btu gas is a highly speculative but potentially attractive technology. Its main advantages are that it eliminates the need for mining coal and provides a means for utilizing otherwise unusable coal resources. Four techniques for burning coal underground are under development--packed bed, longwall generator, steeply dipping bed, and linked vertical well. This subprogram receives the least amount of funding among the nine subprograms and is not expected to be ready for commercial use until around 2000.

*Methanation is the reaction of carbon monoxide and hydrogen which produces methane and water. This process steps low/medium-Btu gas up to high-Btu gas. Methane is the main ingredient in natural gas.

Magnetohydrodynamics (MHD) subprogram

MHD*, a type of advanced power system, has been singled out by ERDA for intensive development. The major objective of the subprogram is to develop an electrical generation system utilizing coal as the primary fuel.

A recent report, partially funded by ERDA, stated that MHD's future value in power generation is highly controversial. Small companies have defended MHD technology while larger companies see more potential in gas turbine technology. The reasons expressed for this difference are that gas turbines offer greater efficiency and the technical problems with MHD, particularly using coal as a fuel, makes commercialization risky. None of the companies surveyed for the report were pursuing MHD research. Section 107 of Public Law 93-404 directed ERDA to immediately undertake the design and planning of an MHD engineering test facility to provide the data for construction of a commercial scale MHD plant in the 1980s. ERDA is committed to developing and operating a commercial scale demonstration MHD electric powerplant by the late 1980s. ERDA is hoping that as encouraging results of pilot scale efforts begin to appear, industry will be enticed to cofund further development.

Technical problems being addressed are the development of durable materials and equipment capable of withstanding high temperatures and the manufacture of special magnets weighing 2,000 tons.

Advanced power systems subprogram

Steam turbine driven generator systems which approach 40-percent efficiency produce almost all of the baseload

*MHD generates electricity directly by forcing a hot stream of coal-combustion gases or other electrically conductive fluid through a magnetic field.

electric power in the United States. ERDA's advanced power systems subprogram is trying to increase the efficiency ratio by developing high temperature advanced gas turbines that can be combined with available low temperature steam systems.* ERDA is supporting research for developing three turbines it considers most promising-- open cycle gas turbine, closed cycle gas turbine, and alkali metal vapor turbine.

Development of the open cycle gas turbine is considered to be further advanced than the other two turbines. ERDA considers the demonstration of full-scale turbines will be accomplished after uncertainties concerning cost and risk are resolved at the "technology readiness" stage bypassing the need for pilot plant scale development.

At least 30 large gas turbines which burn natural gas and oil are commercially producing electricity. But experiments to drive gas turbines on coal have resulted in the clogging and corrosion of the turbine's machinery. ERDA expects to overcome these technical problems in the mid-term (1985-2000). Successful operation of advanced power systems depends, however, on the ability to produce clean synthetic fuel. An ERDA official interviewed is worried that ERDA's coal conversion processes may not even be able to produce enough synthetic fuel within the next 10 years to even be able to perform tests on the turbines.

Demonstration plant subprogram

The objective of the demonstration plant subprogram is to demonstrate, on a near commercial scale, the technical and economic feasibility of selective coal technology. The successful operation of demonstration plants will facilitate the timely transfer of coal conversion and utilization techniques to the private sector. ERDA's plan is to cooperate with private industry in the design, construction, and operation of demonstration plants. The design phases will be funded by the Government, with the construction and operation phases being cost shared, 50 percent from industry and 50 percent from the Government.

*Combined cycles consist of gas turbines (essentially a stationary jet engine) that are used to generate electricity. In addition, the hot exhaust gases are captured and used in a conventional boiler (called a waste heat recovery boiler).

To date, one contract has been awarded for a plan to demonstrate the conversion of coal to clean boiler fuel. Detailed designs for the plant are underway. However, because of technical problems the project has been delayed about two years. ERDA is also presently considering five proposals for a high-Btu gas demonstration plant and 14 proposals for three low-Btu gas demonstration plants for specific electric power utility or industrial uses. Responses to ERDA's proposals for constructing demonstration plants are not limited to those projects being developed by ERDA. And no one really knows if any processes being developed by ERDA will eventually advance to the demonstration plant phase.

ERDA currently estimates that liquefaction, high-Btu, low-Btu, and direct combustion demonstration plants will complete operation by 1985. Assuming the demonstration program is successful, the second generation processes could be ready for initial commercial application by 1985.

Table 2

Fossil Demonstration Plants Division Planned Program
Schedule for Second Generation Processing

	<u>Operation Dates</u>
Clean boiler fuel (Coalcon)	<u>a/Fiscal</u> years 1980-83
Pipeline A&B (high-Btu)	Fiscal years 1981-83
Fuel gas utility (low-Btu/medium-Btu)	Fiscal years 1981-83
Fuel gas industrial (low-Btu/medium-Btu)	Fiscal years 1981-83
Fuel gas small industrial (low-Btu/ medium-Btu)	Fiscal years 1980-81
Direct combustion	Fiscal years 1982-84
Advanced liquefaction	Fiscal years 1983-85
Design time is estimated	2-1/2 years
Construction time is estimated	2-1/2 years
Operations time is estimated	<u>2 years</u>
Total	7 - 8 years

a/This project has been delayed about 2 years while a technical assessment and additional research and development are performed.

ERDA's demonstration plant subprogram aims at transferring second generation coal utilization and conversion processes to the private sector by proving the technical and economic viability of selected processes. No demonstration plant has yet been operated, but ERDA believes that once this is accomplished little technical risk should exist in scaling demonstration plants up to commercial size.

ERDA's scheduling shows that the seven coal demonstration plants now being planned will not be completed until 1980-85, if the projects proceed as planned. Assuming the current pace of development continues, it appears highly unlikely that second generation coal conversion techniques can begin having any commercial impact until the late 1990s.

Advanced research
and supporting
technology subprogram

This subprogram supports ERDA's other coal subprograms by performing supporting research and system studies. The general objective of the advanced research and supporting technology subprogram is to develop third generation coal conversion and utilization techniques, and perform research to improve second generation techniques being developed by ERDA. Research projects are grouped into four main categories--material and components, conversion processes, direct utilization technology, and systems studies.

POSSIBLE FUTURE CHANGES IN TRANSPORTATION
OF COAL TO PUBLIC UTILITIES

Working with Bureau of Mines 1/ and Federal Power Commission data 2/ we examined the potential intermodal shifts in the transport of coal within and between regions* in 1985. This analysis did not consider new national initiatives affecting utilities or industrial users of gas or oil. Such factors would further affect the shifts between transport modes as well as between and within regions.

Based upon these data and projections made from them, coal transportation to utilities shows the following patterns:

Table 1

At Point of Origin
Percent Share of the Market

Method of transportation	Northeast		Southeast		Southwest		Northwest		National	
	1975	1985	1975	1985	1975	1985	1975	1985	1975	1985
Railroad	57	59	36	57	40	32	66	69	57	58
Trucks	14	13	21	14	25	54	13	14	15	19
Water	25	25	25	17	-	-	8	4	21	15
Other*	<u>4</u>	<u>3</u>	<u>18</u>	<u>12</u>	<u>35</u>	<u>14</u>	<u>13</u>	<u>13</u>	<u>7</u>	<u>8</u>
Total	<u>100</u>	<u>100</u>	<u>100</u>	<u>100</u>	<u>100</u>	<u>100</u>	<u>100</u>	<u>100</u>	<u>100</u>	<u>100</u>

*Includes slurry pipelines, trams, conveyors, etc..

*With the exception of a portion of Tennessee, utilities were grouped the same as the mining districts established by BOM and were combined as shown on the map, p. IV.5.

Note: Numbered footnotes to app. IV are on p. IV.6.

The foregoing table shows that transportation growth could vary among regions and transportation modes, reflecting particular producer/consumer market decisions. Note the relative stability of the Northeast and Northwest compared to the relative changes among modes in the Southeast and Southwest. Also note the relative increase for trucking on a national basis compared to a relative decrease for water transportation.

The following table shows projected increases in traffic by region and mode of transport.

Table 2

<u>Mode of trans- portation</u>	<u>At Point of Origin</u> <u>Projected Traffic Growth by Mode</u>				
	<u>Northeast</u>	<u>Southeast</u>	<u>Southwest</u>	<u>Northwest</u>	<u>National</u>
	<u>1975-85</u>	<u>1975-85</u>	<u>1975-85</u>	<u>1975-85</u>	<u>1975-85</u>
----- (percent increase) -----					
Railroads	31	141	166	299	86
Truck	13	-	621	321	125
Water	28	-	-	112	31
Other*	11	-	27	153	53

*Includes slurry pipelines, trans, conveyors, etc..

The above tables depict coal traffic among carriers and regions in relative terms. The following table compares interregional movements in absolute terms.

Table 3

Inter-Regional Movements of Coal
By Mode of Transport

<u>To</u> :	<u>Northeast</u>				<u>Southeast</u>			
	<u>Rail</u>		<u>Water</u>		<u>Rail</u>		<u>Water</u>	
	<u>1975</u>	<u>1985</u>	<u>1975</u>	<u>1985</u>	<u>1975</u>	<u>1985</u>	<u>1975</u>	<u>1985</u>

----- (Million tons) -----

From:

North-east	-	-	-	-	24	32	9	11
North-west	15	26	5	10	0	28	-	-
South-west	-	-	-	-	-	-	-	-
Total	<u>15</u>	<u>26</u>	<u>5</u>	<u>10</u>	<u>24</u>	<u>60</u>	<u>9</u>	<u>11</u>

<u>To</u> :	<u>Northwest</u>				<u>Southwest</u>			
	<u>Rail</u>		<u>Water</u>		<u>Rail</u>		<u>Water</u>	
	<u>1975</u>	<u>1985</u>	<u>1975</u>	<u>1985</u>	<u>1975</u>	<u>1985</u>	<u>1975</u>	<u>1985</u>

From:

North-east	2	2	2	2	9	14	3	5
North-west	-	-	-	-	3	52	-	-
South-west	<u>4</u>	<u>4</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>
Total	<u>6</u>	<u>6</u>	<u>2</u>	<u>2</u>	<u>12</u>	<u>66</u>	<u>3</u>	<u>5</u>

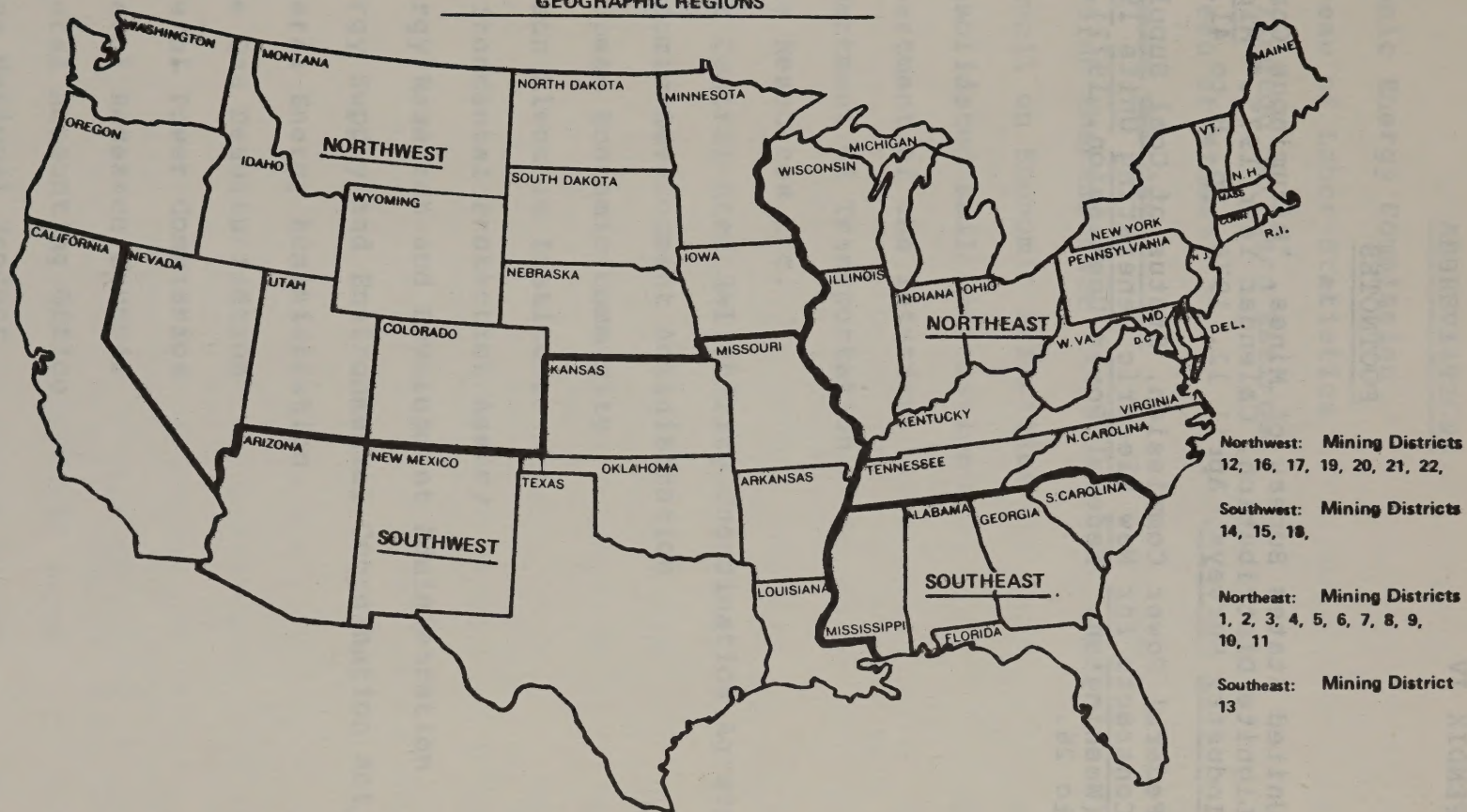
These tables are indications of the possible impacts of regional demands upon the various transport modes currently anticipated by the electrical utilities. However, substantial growth in consumption is indicated for the Southwest region and a somewhat lesser amount is expected for the Southeast. The increase in truck transport may be indicative of the utilities decision to locate facilities near mines.

These tables also show that a large portion of the increase in interregional coal traffic will be in movements from the Northwest to the Southwest and Southeast. For the most part, however, the major share of the coal consumed will not be moved interregionally, but will be used within the region where it is produced.

		1972					1973					1974					1975					1976					1977				
		From					To					From					To					From					To				
		Northwest					Southwest					Northwest					Southwest					Northwest					Southwest				
		West					East					West					East					West					East				
		Total					Total					Total					Total					Total					Total				
1972		10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
1973		10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
1974		10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
1975		10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
1976		10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
1977		10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10

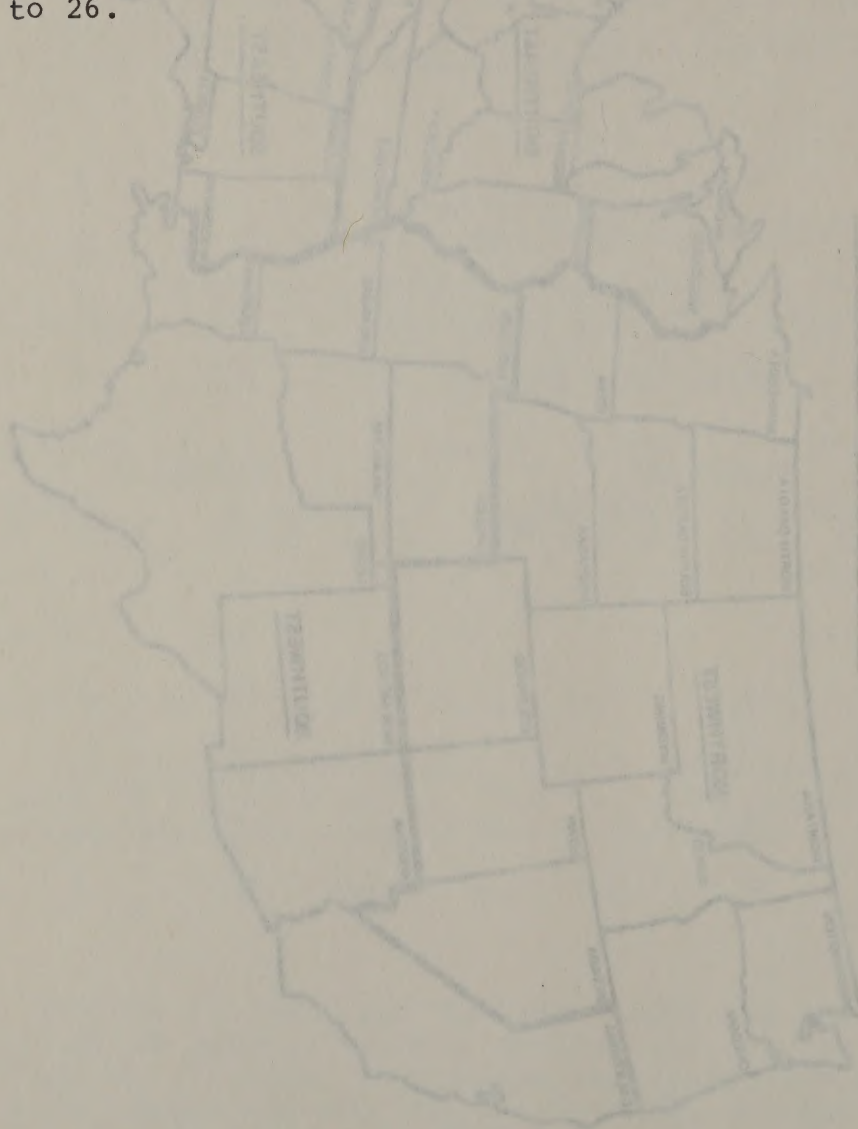
These tables are indicative of the possible impact of regional demands upon the various transport modes currently anticipated by the electric utility industry. However, substantial growth in consumption is indicated for the Southwest region and a somewhat lesser amount is expected for the Southeast. The increase in interregional transport may be indicative of the utilities' decision to locate facilities near mines.

CHART I
SEGREGATION OF UTILITY INSTALLATIONS
AND MINING DISTRICTS INTO
GEOGRAPHIC REGIONS



FOOTNOTES

- 1/United States Bureau of Mines, "Bituminous Coal and Lignite Distribution, Calendar Year 1975," Mineral Industry Surveys, April 12, 1976, pp. 8 to 41.
- 2/Federal Power Commission, Status of Coal Supply Contracts for New Electric Generating Units 1976-1985 (Washington: Federal Power Commission, 1977), pp. 24 to 26.



ABBREVIATIONS

AEC	Atomic Energy Commission
BLS	Bureau of Labor Statistics
BN	Burlington Northern Railroad
BOM	Bureau of Mines
bpd	Barrels per day
Btu	British thermal unit
CEP	Council on Economic Priorities
Conrail	Consolidated Rail Corporation
DOI	Department of the Interior
DOT	Department of Transportation
DRI	Data Resources Inc.
ECAR	East Central Area Reliability Coordination Agreement
EDA	Economic Development Administration
EEC	European Economic Community
EEI	Edison Electric Institute
EPA	Environmental Protection Agency
ERDA	Energy Research and Development Administration
ESECA	Energy Supply and Environmental Coordination Act
FEA	Federal Energy Administration
FGD	Flue Gas Desulfurization
FPC	Federal Power Commission
FRC	Federal Research Council
GAO	General Accounting Office
GNP	Gross National Product
ICC	Interstate Commerce Commission

IEA	International Energy Agency
kw	Kilowatt
kwh	Kilowatt hour
LNG	Liquified natural gas
MAIN	Mid-America Interpool Network
MW	Megawatt
MESA	Mining Enforcement and Safety Administration
MHD	Magnetohydrodynamics
NAS	National Academy of Sciences
NCA	National Coal Association
NCM	National Coal Model
NEO	National Energy Outlook
NEPA	National Environmental Policy Act
NERC	National Electric Reliability Council
NSF	National Science Foundation
OPEC	Organization of Petroleum Exporting Countries
OTA	Office of Technology Assessment
PIES	Project Independence Evaluation System
ppm	Parts per million
SRI	Stanford Research Institute
TVA	Tennessee Valley Authority
TSC	Transportation Systems Center
UMWA	United Mine Workers of America
USG	Under Secretaries Group
USGS	United States Geological Survey
USRA	United States Railway Association

GLOSSARY

Ambient	Conditions in the vicinity of a reference point, usually related to the physical environment (e.g., the ambient temperature is the outdoor temperature).
Anthracite coal	A high-rank coal with high fixed carbon, percentages of volatile matter and moisture; a late stage in the formation of coal.
Aquifer	Water-bearing permeable rock, sand, or gravel.
Auger mining	Generally practiced but not restricted to hilly coal-bearing regions of the country. Utilizes a machine designed on the principle of the auger, which bores into an exposed coal seam and conveys the coal to storage site or bin for loading and transporting.
Baseload	Minimum load of a power generator over a given period of time.
Bituminous coal	An intermediate-rank coal with low to high fixed carbon, intermediate to high heat content, a high percentage of volatile matter, and a low percentage of moisture.
British thermal unit (Btu)	The amount of energy necessary to raise the temperature of one pound of water by one degree Fahrenheit.
Coal	A combustible natural solid formed from fossilized plants.
Coking/metallurgical coal	Designates certain bituminous coal which when heated at high temperature in the absence of air, softens then solidifies into a porous solid mass that is called coke. Only bituminous coal possesses such properties and certain bituminous coal possesses coking properties in a greater degree than others. Coke is used in blast furnaces.

Combined cycle	Combination of a steam turbine and a gas turbine in an electrical generation plant.
Continuous miner	A single machine used in underground mining which accomplishes excavation, loading, and transportation.
Demonstrated reserve base (coal)	Portion of identified coal resources to depths of 1,000 feet and seam thickness similar to those from which coal is currently being mined, generally 28 inches or more.
Eminent domain	The right of a government to appropriate private property for public use, usually with compensation to the owner.
Flue gases	Gases usually carbon dioxide, water vapor, oxides of nitrogen, and other trace gases which result from combustion processes.
Fluidized bed	A body of finely crushed particles with gas blown through them. The gas separates the particles so that the mixture behaves like a turbulent liquid.
Fly ash	Lightweight solid particles which are carried by stack gases.
FOB mine	The price of coal at the mine gate. It does not include cost of transporting the coal to its final destination.
Gasification	Commonly refers to the conversion of coal to a gaseous fuel.
Generator, electric	A mechanism which converts mechanical energy to electrical energy.
Heat rate	An expression of the conversion efficiency of a thermal powerplant or engine, as heat input per unit of work output: for example, Btu per kwh.

High-Btu gas	An equivalent of natural gas, predominately methane; energy content is usually 950 to 1,000 Btus per cubic foot.
Identified resources (coal)	Deposits of coal whose location, quality, and quantity have been mapped and are known to exist from geologic evidence supported by engineering and measurements of geologic reliability. Includes deposits in beds of minimum thickness of 14 to 30 inches, depending upon rank to depths of 3,000 feet.
Kilowatt	One thousand watts.
Kilowatt hour	The total energy developed by a power of one kilowatt acting for one hour; a common unit of electric power consumption.
Lignite coal	The lowest rank coal with low heat content and fixed carbon and high percentages of volatile matter and moisture; an early stage in the formation of coal.
Liquefaction	Commonly refers to the conversion of coal to liquids.
Low-Btu gas	Gas obtained by partial combustion of coal with air; energy content is usually 100 to 200 Btus per cubic foot.
Megawatt	A million watts or a thousand kilowatts and is used to measure the amount of power as electricity that can be produced by a facility at any one time.
Methane	A colorless, odorless, flammable, gaseous hydrocarbon that is a product of decomposition of organic matter in marshes or mines or the carbonization of coal.

Micron	A unit of length equal to one thousandth of a millimeter.
Overburden	The rock, soil, etc., covering a mineral to be mined.
Particulates	Microscopic pieces of solids which emanate from a range of sources and are the most widespread of all substances that are usually considered pollutants.
Peak load	The maximum instantaneous load or the maximum average load over a designated interval of time, also known as peak power.
Quadrillion	The cardinal number represented by 1 followed by 15 zeros; one quadrillion Btus of energy is the equivalent of 180 million barrels of oil.
Reserves (coal)	Portion of coal resources in the ground that can be economically extracted at current prices (costs) using current technology.
Resources (coal)	Coal deposits in the ground as of a stated date. Coal resources are classified by the USGS as identified and undiscovered resources.
Scenario	An outline of a hypothesized chain of events.
Scrubber	Equipment used to remove pollutants such as sulfur dioxide or particulate matter from stack gas emissions usually by means of a liquid solvent.
Seam	A bed of coal or other valuable mineral of any thickness.
Slurry	A mixture of a liquid and solid. Slurries of oil and coal or water and coal are used in coal processing and transportation.

Stack gas	Gases resulting from combustion.
Stack gas cleaning	Referring to the removal of pollutants from combustion gases before those gases are emitted to the atmosphere.
Steam coal	A designation for a whole range of coal that can be utilized in boilers to produce steam for purposes of generating electricity.
Strip mining	A mining method which uses giant power shovels or other earth-moving equipment to remove overburden that covers the coal seam. When the coal is exposed, it is broken up usually by explosives and loaded by smaller power shovels into huge trucks.
Stripping ratio	Cubic yards of overburden per ton of coal recovered.
Subbituminous coal	A low-rank coal with low fixed carbon and high percentages of volatile matter and moisture.
Sulfur dioxide	One of several forms of sulfur in the air; an air pollutant generated principally from combustion of fuels that contain sulfur.
Unit train	A term used to designate a train which carries a single commodity. Coal unit trains normally contain about 100 cars with each car having a capacity of about 100 tons of coal.
Volatile	Readily vaporizable at a relatively low temperature.

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EXECUTIVE OFFICE OF THE PRESIDENT
ENERGY POLICY AND PLANNING
WASHINGTON, D.C. 20500

August 26, 1977

Dear Mr. Staats:

The GAO report, "U.S. Coal Development: Promises and Uncertainties," addresses a number of issues of vital importance for energy policy. The only major area of substantive disagreement is the conclusion reached by the report that no more than one billion tons of coal could be produced between now and 1985.

One reason advanced by GAO is that strip mine legislation will constrain expansion. Since the new strip mine legislation has not been translated into regulations, it is very difficult to understand the basis for this conclusion. However, regardless of the stringency of the implementing rules, it is doubtful that the effects would produce a substantial shortfall.

GAO raises questions about possible transportation constraints. However, recent investigations by the Department of Transportation demonstrate that railroad capacity is generally adequate and that the capital requirements for additional capacity would represent only a small portion of prospective railroad investment.

On the demand side, GAO's estimate of shortfall is based on expected impacts of strict enforcement of air quality regulations. Although no quantitative analysis of the major economic sectors is presented, GAO focuses arguments on three policies: best available control technology (BACT) requirements; prevention of significant deterioration (PSD) policies in clean air areas; and EPA's offset policy for non-attainment areas.

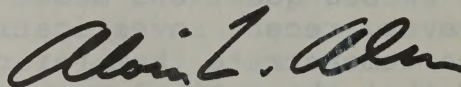
Since BACT requirements do not come into effect until 1982, the impacts on coal use will be minimal by 1985. The PSD policy is not likely to affect coal consumption substantially. Studies indicate that large coal-fired power plants with BACT can be located as close as six miles from a Class I area that has the most stringent deterioration limits. Industrial units, which are similar, can be located even closer. EPA's offset policy for non-attainment areas will

not affect new power plants because they will not be built in non-attainment areas. Also, conversions generally increase sulfur oxide emissions but reduce particulate emissions, whereas most non-attainment areas violate particulate standards and not sulfur oxide.

The GAO report does not address how much of an increase in coal production can be achieved due to the initiatives in the National Energy Plan. In general, the report seems to be criticizing the base case projection that without the National Energy Plan, production will be about one billion tons per year. The one billion ton base estimate of coal production of 1985 is consistent with several different surveys, including GAO's survey of producers.

Although we disagree with GAO's assessment, there are a number of factors that could limit coal demand and hence total coal use. The Department of Energy plans to monitor coal production carefully and if shortfalls occur, the Department will take or recommend appropriate remedial action.

Sincerely,


Alvin L. Alm

The Honorable Elmer B. Staats
Comptroller General of
the United States
Washington, D.C. 20548

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VIII.2

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